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NEW ELECTRIC POWER TECHNOLOGIES

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Foreword

This report responds to a request from the House Committee on Science and Technology and its Subcommittee on Energy Development and Applications to analyze a range of new electric power generating, storage, and load management technologies.

OTA examined these technologies in terms of their current and expected cost and performance, potential contribution to new generating capacity, and interconnection with the electric utility grid. The study analyzes increased use of these technologies as one of a number of strategies by electric utilities to enhance flexibility in accommodating future uncertainties. The study also addresses the circumstances under which these technologies could play a significant role in U.S. electric power supply in the 1990s. Finally, alternative Federal policy initiatives for accelerating the commercialization of these technologies are examined.

OTA received substantial help from many organizations and individuals in the course of this study. We would like to thank the project's contractors, who prepared some of the background analysis, the project's advisory panel and workshop participants, who provided guidance and extensive critical reviews, and the many additional reviewers who gave their time to ensure the accuracy of this report.

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Overview and Findings

During the 1970s, the environment within which utilities made investment decisions changed from a relatively predictable continuation of past trends to a highly uncertain and complicated maze of interrelated financial, regulatory, and technology considerations. As electric utilities face the 1990s, the experiences of the 1970s have made them much more wary of the financial risk of guessing wrong and overcommitting to large central station coal and nuclear plants. At the same time, the possibility of being unable to meet electricity demand exists, causing growing concern among utilities as the next decade approaches.

As a result, utilities are now taking steps to enhance their flexibility in accommodating future uncertainties. In addition to continued and primary reliance on conventional technologies, supplemented by coal combustion technology enhancements to reduce pollution emissions and increase efficiency, utilities are considering a variety of less traditional options. These include life extension and rehabilitation of existing generating facilities, increased purchases from and shared construction programs with other utilities, diversification to nontraditional lines of business, increased reliance on less capital-expensive options such as load management and conservation, and smaller scale power production from a variety of conventional and alternative energy sources. Such options offer utilities the prospects of more rapid response to demand fluctuations than traditional, central station powerplants.

The Role of New Technologies

This report focuses on a number of alternative generating technologies, as well as on energy storage and load management technologies that are new or have not traditionally been used by utilities or other power producers. It examines their technical readiness and the conditions under which they could contribute to meeting electricity demand in the 1990s. The study does not examine in detail the more traditional technologies of central station coal or nuclear, nor does it analyze advanced nuclear or combined-cycle systems and enhancements to pulverized coal plants such as supercritical boilers, limestone injection, or advanced scrubber systems. In addition, we do not discuss more mature renewable technologies such as low-head hydropower or refuse- or wood-fired steam plants. Many of these options are discussed in other OTA reports. It is important to note, however, that these traditional options and their variations are likely to remain the principal choice of electric utilities in the 1990s.

It is convenient to divide the technologies considered in this assessment into two basic groups in order to discuss appropriate policy options:

1. The first consists of technologies envisioned primarily for direct electric utility applications and includes integrated gasification combined-cycle (IGCC); large (>100 MW) atmospheric fluidized-bed combustors (AFBC); large (>100 MW) compressed air energy storage (CAES) facilities; large (>50 MW) geothermal plants; utility-owned, fuel cell powerplants, and solar thermal central receivers.
2. The second group consists of technologies that are characterized as suitable either for utility or nonutility applications, and includes small (<100 MW) AFBCs in nonutility cogeneration applications; small (<100 MW) CAES; fuel cells; small (< 50 MW) geothermal plants; batteries; wind; and direct solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

Virtually all of these technologies offer the potential for sizable deployment in electric power applications beyond the turn of the century. The potential is high because these technologies offer one or more advantages over most conventional generating alternatives. In general, they would constitute a diverse array of equipment capable of flexibly meeting future demand growth and increasing the clean and efficient utilization of abundant domestic energy resources. Some are **smaller scale technologies with modular designs that permit capacity additions to be made in small increments with less concentration of financial assets and short lead-times between commitment and coming "on-line."** Utilities may be able to realize notable financial benefits from smaller scale capacity additions, even when the capital cost per kilowatt of smaller units is as much as 10 percent more than that of large-scale capacity additions. Other attractive features of these technologies include **reduced environmental impacts, the potential for fewer siting and regulatory barriers, and improved efficiency and fuel flexibility**.

Despite these long-term advantages, however, **at the current rate of development very few of these technologies are likely to be deployed extensively enough in the 1990s to make a significant contribution to U.S. electricity supply**. In both groups of technologies, the ultimate goal of research, development, and demonstration is to reduce costs and increase performance so that these new technologies can compete with more traditional technologies.

For the first group, the likelihood of long preconstruction and construction lead-times—up to 10 years—is the primary constraint. Although these technologies have the potential for much shorter lead-times—5 to 6 years—problems associated with any new, complex technology may require construction of a number of plants before that potential is met. If the longer lead-times are needed, deployment in the 1990s will be limited because of the short time remaining to develop the technologies to a level utilities would find acceptable for commercial readiness.

Technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. **For most of them to make a significant contribution in the 1990s, however, their development will have to be stepped-up in order to reduce cost to levels acceptable to utility decisionmakers and nonutility investors, and to resolve cost and performance uncertainties**.

In addition to new generating and storage technologies, **load management** is being pursued actively by some utilities. **Widespread deployment among utilities in the 1990s, however, will depend on: continued experimentation by utilities to resolve remaining operational uncertainties; further refinement of load management equipment including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer response to different load controls and rate incentives.**

For load management as well as certain generating technologies—specifically fuel cells, photovoltaics, solar thermal technologies, and batteries—economies of scale in manufacturing could reduce cost substantially. Of course, these reduced costs will not be realized without substantial demand from utilities or other markets.

Finally, the relative advantages of both groups of new generating technologies and load management varies by region. Factors such as demand growth rates, age and type of existing generating facilities, natural resource availability, and regulatory climate all influence technology choice by utility and nonutility power producers.

Steps for Accelerated Development and Deployment

If electricity demand growth should accelerate by the early 1990s, the first choice of utilities is likely to be conventional central station generation capacity. Because of many well-documented problems, however, there may be severe difficulties in relying on this choice alone and utilities could face serious problems in meeting demand. As a consequence, it may be prudent to accelerate the availability of the technologies discussed in this study. Although not all the technologies would be needed under such conditions, if they were available, the market would be able to offer a more versatile array of choices to electricity producers.

The steps necessary to make these technologies available vary. **With the first group of technologies, it is necessary first to resolve cost and performance uncertainties within the next 5 to 6 years, and then to assure the 5- to 6-year lead-time potential is met for early commercial units**.

In the wake the experiences of the last decade, utility decisionmakers, in particular, are now very cautious about new technology, and they impose rigorous performance tests on technology investment alternatives. **This conservatism makes advanced commercial demonstration projects even**

more important. For the **basic** designs of the AFBC, IGCC, and utility-scale geothermal plants, **the current development and demonstration schedule appears adequate to allow these technologies to be ready by the 1990s.** The cooperative industry-government demonstration efforts, managed by the utilities, have a good track record. **The transition from demonstration to early commercial units, however, will have to be accelerated if the technologies are to produce a significant amount of electricity in the 1990s.** Moreover, variations in basic designs or more advanced designs to enhance performance characteristics further will require additional research and development.

Lead-times being experienced by some early commercial projects in both groups of technologies have been longer than anticipated, partially due to the time required for regulatory review. **Working closely with regulators and taking steps to assure quality construction for the early commercial plants could greatly assist the achievement of shorter lead-times. Emphasis on smaller unit size—200 to 300 MW—would facilitate these actions.**

For the technologies in the second group defined earlier, where cost and performance are of greatest concern, one approach to accelerating development would be to increase or concentrate Federal research and development efforts on these technologies. This could be particularly effective for photovoltaics, solar thermal parabolic dishes, and advanced small geothermal designs.

There are other approaches, though, in which Federal efforts can assist technology development. The reemergence of nonutility power production as a growing industry in the United States is providing, and can continue to provide, an important test bed for some of these new generating technologies. **For nonutility power producers, the Renewable Energy Tax Credit (RTC) and the recovery of full utility avoided costs under the Public Utility Regulatory Policies Act of 1978 (PURPA) have been crucial in the initial commercial development and deployment of wind and solar power generating technologies.** In particular, with declining direct Federal support for renewable technology development, **the RTC has supported both development of advanced designs as well as commercial application of mature designs.**

Without some continuation of favorable tax treatment, based either on capacity or production, development of much of the domestic renewable power technology industry may be significantly delayed. Some technologies such as geothermal and wind have advanced to the point, however, where industry probably would continue development, although at a much slower pace, even if the RTC were withdrawn.

Cooperative agreements among utilities, public utility commissions, and the Federal Government can provide another mechanism for supporting advanced commercial demonstration projects of technologies from both groups. A portion of such projects could be financed with an equity contribution from the utility and the remainder through a "ratepayer loan" granted by the public utility commission, possibly guaranteed by the Federal Government.

Other Actions

The rate of deployment of new generating technologies also will be affected by the extent to which utilities and nonutility power producers can resolve such issues as interconnection standards, coordination with utility resource plans, and procedures for gaining access to transmission for interconnection and wheeling of power to customers or other utilities.

The contribution of new generating technologies is likely to be enhanced if utilities are allowed to enjoy the full benefits afforded to qualifying facilities under PURPA and if the restrictions on the use of natural gas in power generation are removed. The latter would allow the use of natural gas as an interim fuel during the development of "clean coal" technologies, and give utilities and nonutility power producers added flexibility.

The new generating technologies that appear to show the most promise for significant deployment in the 1990s are those that can serve ad-

ditional markets beyond the domestic utility grid. Such markets are particularly important while the need for new electric generating capacity is low, and while the cost and performance of these technologies are uncertain in grid-connected applications. Indeed, **if priorities must be set in supporting developing technologies, it is important to note that broad market appeal is as important as commercial readiness to their timely development.** In this respect, Federal efforts to help industry exploit foreign markets could be especially important.

The rate of new generating technology deployment also is tied closely to future trends in avoided cost and other provisions established by PURPA. **Long-term energy credit and capacity payment agreements between utilities and nonutility power producers could accelerate deployment. So could mandatory minimum rates or fixed price schedules for utility payments to nonutility power producers or for use as a basis for cost recovery by utilities themselves.**

Finally, to increase the number of **nonutility power projects** employing new electric generating technologies, steps to streamline the mechanisms for wheeling of power through utility service territories might open up new markets for the electricity they produce and thereby stimulate their development.

Chapter 1

Introduction

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Chapter 1
Introduction

THE POLICY CONTEXT

For the U.S. electric power industry, the 1970s was a decade of unprecedented change. Beginning with the 1973-74 Arab oil embargo, forecasts of electricity demand growth and costs, based solely on past trends, proved virtually useless. Utility decisionmakers found themselves caught in a complicated and uncertain maze of interrelated financial, regulatory, and technological considerations.

Utilities had to pay, on average, 240 percent more for oil and 385 percent more for natural gas, in real dollars, in 1984 than in 1972. These price increases drove them to "back out" of oil- and gas-fired generation and in favor of coal and nuclear plants. Oil dropped from 16 to 5 percent in the utility fuel mix and gas from 22 to 12 percent between 1972 and 1984. But construction costs of new powerplants, particularly nuclear, rose dramatically during this period due to a combination of factors—increased attention to environmental and safety issues (leading to extended construction lead-times and added equipment costs), an unpredictable regulatory environment, an inflation-driven doubling of the cost of capital, and poor management in some cases. The higher costs of fuel and capital meant higher electricity costs, and utilities sought higher rates for the first time in decades. In addition, most utilities seriously underestimated the price elasticity of electricity demand. Growth in demand plummeted from 7 percent a year to less than 2.5 percent by the end of the decade as consumers used less electricity and used it more efficiently.

During the 1970s some electric utilities were brought to the brink of bankruptcy when forced to cancel large, unneeded powerplants; commitments to these plants had been made long before it was realized that electricity demand had been overestimated. The eroding revenue base accompanying declining demand growth coupled with the increasingly costly construction programs already underway left the industry for the most part struggling financially as bond ratings and stock prices fell precipitously.

Even now in the mid-1980s, although utilities have for the most part recovered from the financial trauma of the 1970s,[1] the scars remain. The process by which utilities initiate, analyze, and implement investment decisions was changed fundamentally by the 1970s experience. In the 1960s, power system planners analyzed capacity expansion plans based on life cycle electricity costs of alternative plans. System planners now work much more closely with financial planners to analyze carefully the cash flow of the alternatives as well as the flexibility of alternative plans in accommodating unanticipated changes in demand, capital cost, interest rates, environmental regulation, and a host of other considerations. In short, their decisionmaking process has become much more financially cautious as well as more complex.

While power system planners for most utilities continue to focus on conventional generating technologies, as well as advanced combined-cycle systems or enhancements to pulverized coal plants such as supercritical boilers, limestone injection, or advanced scrubber systems, they now consider a much broader range of strategic options, including: life extension and rehabilitation of existing generating facilities; increased purchases from and shared construction programs with neighboring utilities; diversification to nontraditional lines of business; increased reliance on load management; and increased use of small-scale power production from a variety of both conventional and alternative energy sources. In addition, most utilities have greatly expanded their conservation programs, both because it now offers the lowest cost means of meeting demand in many cases, and it provides the utility with a way to reduce future demand uncertainty. In considering these various options, utilities hope to chart an investment course that will enable them both to meet the largely unpredictable demand for electricity in the future and to maintain their financial health.

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[1] Actually, even though 1984 was a very good year for utility stocks on average, as of early 1985, utilities fall roughly into three categories of stock performance: some with little or no construction are quite strong, some with low to modest construction programs are stable but lackluster in performance, and finally some with large nuclear facilities under construction (or recently canceled) are still doing very poorly.

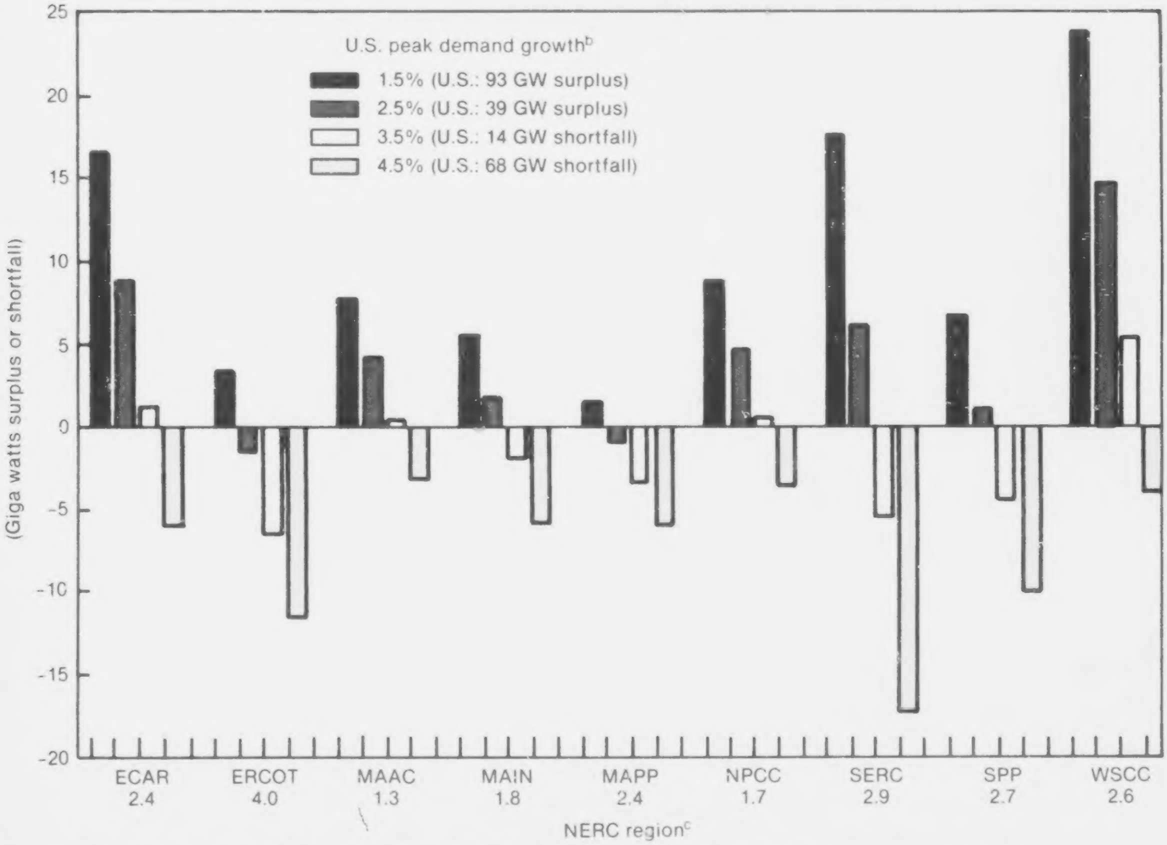
The most critical legacy of the 1970s is the uncertainty in electricity demand growth. After 1972, not only did the average annual demand growth rate drop to less than a third of that of the previous decade, but the year-to-year changes became erratic as well. Users of electricity were able to alter the quantity they used much more quickly than utilities could accommodate these changes with corresponding changes in generating capacity. Moreover, as of 1985, there is saturation in some markets—many major appliances in homes—and the future of industrial demand is clouded as many large industrial users of electricity, such as aluminum and bulk chemicals, are experiencing decline in domestic production due to foreign competition. At the same time, rapid growth continues in other areas such as space conditioning for commercial buildings, industrial process heat, and electronic office equipment. Predicting the net impact of these offsetting factors, along with trends toward increased efficiency, has greatly complicated the job of forecasting demand.

Since requirements for new generating capacity over the next two decades depends primarily on electricity demand growth (as well as the rate at which aging plants are replaced with new capacity and, in some regions, net imports of bulk power from other regions), planning for new capacity has become a very risky process. To illustrate the demand uncertainty, this assessment looks at a range of different growth rates—1.5, 2.5, 3.5, and 4.5 percent increases in average annual electricity demand through the end of the century. This range is based on analysis carried in the 1984 OTA study, *Nuclear Power in an Age of Uncertainty*. Figure 1-1 correlates these different demand growth rates with the currently planned generating capacity for 1993 in the regions of the United States defined by the North American Electricity Reliability Council (NERC)—the NERC regions are defined in figure 1-2. In all regions, capacity surpluses are now projected by 1993 if annual demand growth is 1.5 percent; and in seven of the nine regions, there would be capacity surpluses if demand growth is 2.5 percent. But a 3.5 percent growth rate could mean capacity shortfalls in five of the nine regions; and with a 4.5 percent growth, there could be shortfalls in all regions.

At the center of the policy debate over the future of electricity supply is the mix of power generation technologies that will be deployed by either utility or nonutility power producers over the next several decades. Those anticipating a strong resurgence in electricity demand in the 1990s support the building of more large powerplants. They cite economies of scale of such plants that, in their view, would minimize electricity costs over the long run. Others, who believe demand growth to be more uncertain, favor a strategy of flexibility which includes the possibility of small-scale capacity additions as well as increased reliance on other methods of dealing with demand uncertainty such as conservation and load management.

Complicating this controversy is the utilities' evolving attitude toward new technology, another consequence of the 1970s. While traditionally conservative in adopting new technology, the electric utility industry has grown particularly cautious in the wake of its experience with nuclear power. Utilities now impose rigorous economic performance tests on new technology investments. Perhaps because of this caution, projects initiated by nonutility power producers under the Public Utility Regulatory Policies Act (PURPA) since 1978 have served as the principal test bed for first generation commercial applications of many new generating technologies.

Figure 1-1.—1993 U.S. Generating Capacity Surplus or Shortfall Under Alternative Peak Load Growth Scenarios[a]



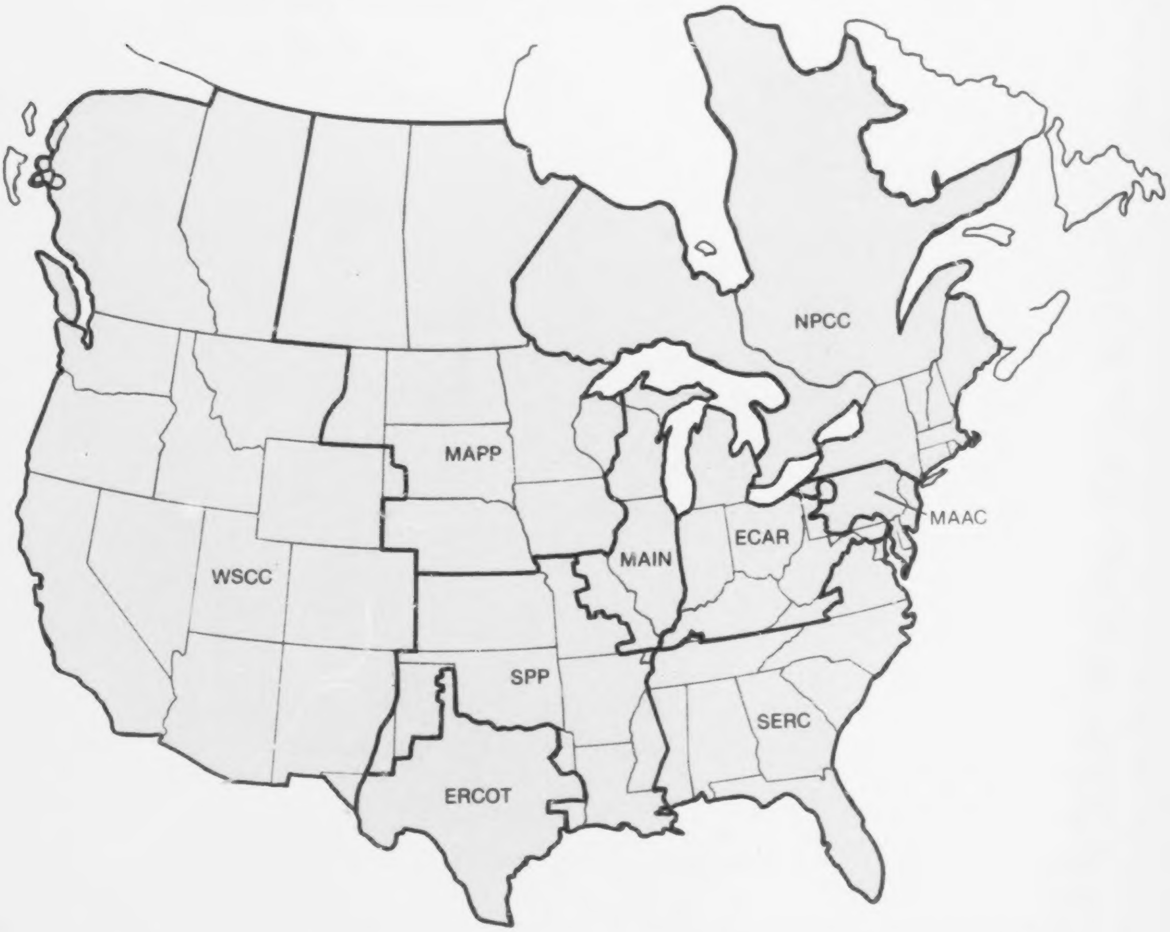
[a] Surplus or shortfall is the projected 1993 capacity less 1993 projected peak load (including 20% reserve margin).

[b] Average annual growth in peak demand for 1983-1993; regional growth rates for the 2.5% reference case are given at the bottom of the chart.

[c] The North American Electric Reliability Council regions are defined in figure 1-2.

SOURCE: Reference projections for installed generating capacity, 2.5 percent average annual growth (national), and regional growth rates are reported in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

Figure 1-2.—Map of North American Electric Reliability Council (NERC) Regions



ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool Network
MAPP	Mid-continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

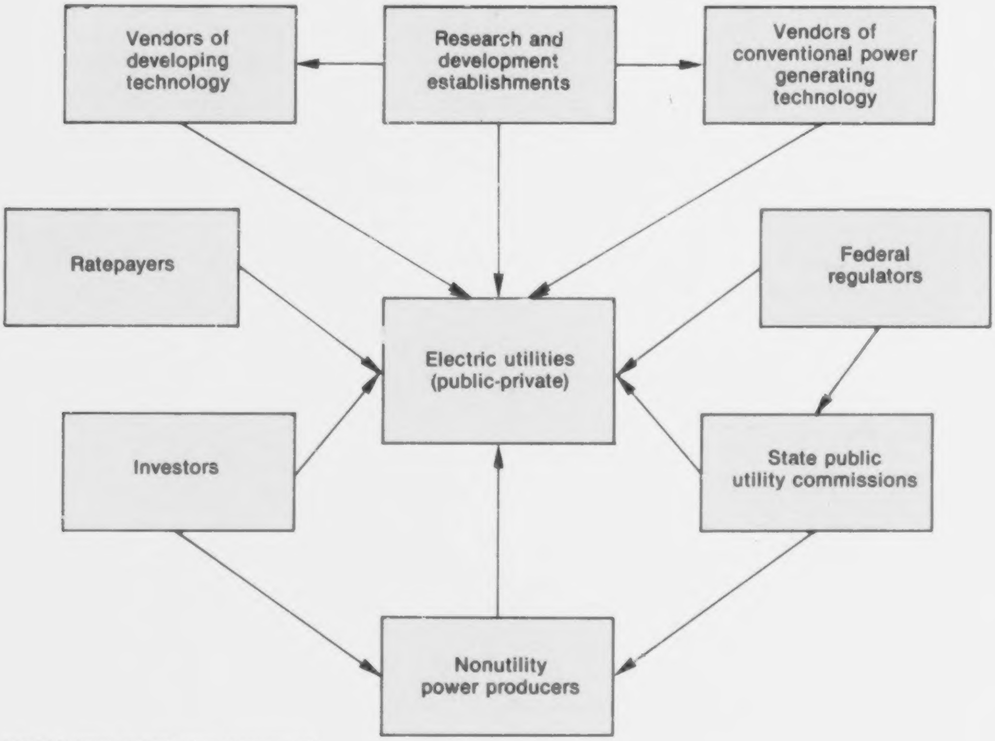
SOURCE: North American Electric Reliability Council (NERC), *NERC At A Glance* (Princeton, NJ: NERC, 1984).

THE PLAYERS

Any Federal policy decision affecting the electric power industry affects a wide range of interests. The changing conditions of the 1970s along with increased activity in new technology development have increased the number of participants who affect the industry. Each brings a very different perspective to electricity policy issues, especially with respect to new technologies. These participants, depicted in figure 1-3, are as follows:

- **Electric utilities**, both public and investor owned, differ widely in financial health, existing facilities and fuel use, and in their attitudes toward new technology.

Figure 1-3.—The Players Shaping the Future of U.S. Electric Power


Vendors of developing technology
Research and development establishments
Vendors of conventional power generating technology
Ratepayers
Federal regulators
Electric utilities (public-private)
Investors
State public utility commissions
Nonutility power producers

SOURCE: Office of Technology Assessment.

- **Nonutility power producers** have reemerged as a potentially important force in the future of electric power in the United States, particularly with respect to application of new technologies. With the enactment of PURPA, such producers (which includes all entities other than electric utilities) have begun to provide a noteworthy source of innovation in electric power generation. The relationship which evolves between these electricity producers and utilities will certainly influence the degree of deployment of new power generating technologies over the next two decades.
- **State public utility commissions** exert considerable influence over utility choices by what is permitted to enter the rate base. Commissions differ widely in their attitudes toward treatment of research and development, rate structure design, cost overruns of construction programs, as well as toward new technology.
- **Federal regulators** such as the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the Environmental Protection Agency, in carrying out their assigned missions, affect the electric power industry profoundly. The prospect of extensive deployment of new technologies over the next several decades may hinge as much on the regulations promulgated by these agencies as on the competitive cost and performance of the technologies.
- **Ratepayers'** response to electricity prices as well as their attitudes on issues such as nuclear power costs, nuclear safety, coal pollution, and acid rain, etc., will play major roles in determining the future of the electric power industry. In particular, ratepayers' response to prices—i.e., their demand for

electricity, and attitudes on electricity supply-related issues—will largely determine the technologies that will be employed in power generation.

- **Investors**' attitudes on the comparative risks in selecting future utility and nonutility power generation projects are important considerations and will affect the financial health of both industries. As the utility industry recovers from a financially troubled period, the degree to which investors are willing to put their money into large new generating plants again will greatly affect utility investment decisions. Similarly, the access of new electricity-generating technologies to traditional (other than venture) capital sources, which is so critical to the continued development of many of these technologies, will depend on investors' perceptions of the technologies' cost and performance prospects.
- **Vendors of conventional power generating technology** have enjoyed a long relationship with the electric utility industry. This relationship heavily influences new technology investment decisions.
- **Vendors of developing technologies** include many businesses that have not traditionally dealt with the electric utility industry. New technology developers, which in many cases also include traditional vendors, range from giant petroleum companies and aerospace firms to small independent firms. In many cases, the newcomers are only beginning to establish working business relationships with electric utilities and other nonutility power producers. For some technologies, these firms are much more diverse in terms of age, size, financial position, etc., than conventional technology vendors. The relationship between such firms and the utilities as well as nonutility power producers is still evolving and will affect future investment decisions.
- **Research and development (R&D) establishments** such as the U.S. Department of Energy and the Electric Power Research Institute (EPRI) are now important forces in the development of new electric power technologies. Traditionally, until the 1970s, research, development, and demonstration of new electric power technologies was primarily within the province of a handful of equipment vendors cited above, in some cases supported by the Federal Government. Increasing Federal involvement in energy R&D in the 1970s and establishment of EPRI in 1972 contributed to expanding the range of public and private entities involved in commercial development of new electric technologies.

OBJECTIVES OF THIS ASSESSMENT

Electric power supply issues have been actively discussed in recent years in Congress as well as by regulators, electric utilities, and other interested parties. All parties have expressed renewed interest in alternatives to large, long lead-time powerplants. In 1981 the House Committee on Banking, Finance, and Urban Affairs requested that OTA examine the prospects of small power generation in the United States, citing that:

> . . . considerations of energy policy have not taken adequately into account the possibilities of decentralizing part of America's electrical generating capabilities by distributing them within urban and other communities.

At this time, the effects of the implementation of PURPA were beginning to appear. This act defined a role for grid-connected, nonutility small power producers in U.S. electricity generation, requiring utilities to interconnect and pay these producers for electricity provided to the grid. During the early 1980s, it became clear that the most active nonutility area of small power production would be (and still is) industrial cogeneration of steam and electricity. Consequently, in 1983 in response to the Banking Committee's request, OTA completed an assessment of industrial and commercial cogeneration.[2]

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[2] U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-192.

As the cogeneration assessment was underway, the effects of errors in electricity demand forecasts and continued demand uncertainty on utility decisionmaking were beginning to be felt throughout the industry as proposed new plants were canceled or deferred indefinitely. These cancellations were particularly damaging to the nuclear power industry which was already struggling to deal with increasing public opposition. OTA completed an assessment of the future of nuclear power which was released early in 1984.[3] In the course of that study, the possibility of resurgent electricity demand growth in the 1990s (argued by some as quite likely) was raised as a very difficult planning issue for the utility industry, particularly if utilities continued to rely on large powerplants at a time when they were financially stressed. To address these issues and to explore benefits of small-scale, short lead-time alternatives to central station powerplants, the House Science and Technology Committee requested that OTA examine the status of such technologies as **photovoltaics, fuel cells, wind turbines, selected geothermal technologies, solar thermal-electric powerplants, atmospheric fluidized-bed combustors, coal gasification/combined-cycle plants, advanced utility-scale electricity storage technologies, and load management**.

In response, in late 1983 OTA undertook this assessment of developing electric generating technologies. The assessment addresses four major issues:

1. What is the current status of new electric generating technologies compared with conventional alternatives and how is their status likely to change over the next 10 to 15 years? In addition, what are the most promising R&D opportunities that could affect the deployment of these technologies over this period and beyond?
2. What is the nature of the industry supporting these technologies (vendors and manufacturers)? And how sensitive is their viability to electric utility orders over the next 10 to 15 years, Federal support (e.g., tax incentives and/or demonstration programs), and foreign competition?
3. What are the regional differences that affect the attractiveness of these technologies to electric utilities and nonutility power producers, particularly compared to other strategic options in those regions such as increased purchases of power from neighboring utilities, life extension of existing facilities, conservation, and so on?
4. What are the alternative public policy initiatives (e.g., tax credits, loan guarantees, demonstration projects, etc.) for accelerating the commercial viability of these technologies?

This OTA assessment focuses on the group of newer developing generating technologies that, while not fully mature, could figure importantly, under some scenarios, in the plans of utility or nonutility producers in the 1990s. Those technologies considered relatively mature including conventional coal and nuclear plants, conventional gas turbines, conventional combined-cycle plants, biomass technologies, vapor-dominated geothermal technology, low-head hydroelectric facilities, and others are not considered in detail. It is important to note, however, that in many cases these technologies are the principal benchmarks against which the technologies considered here will be compared in the 1990s. Also not considered are technologies not likely to contribute significantly to the U.S. generation mix by the 1990s—e.g., fusion, ocean thermal energy conversion, magnetohydrodynamics, and thermionic energy conversion.

This assessment was carried out with the assistance of a large number of experts reflecting different perspectives on the electric power industry—utility executives, system planners, financial planners, State public utility commissioners, environmental and consumer groups, Federal regulators, engineers, technology vendors, nonutility small power producers, and the financial community. As with all OTA studies, an advisory panel comprised of representatives from all these groups met periodically throughout the course of the assessment to review and critique interim products and this report, and to discuss fundamental issues affecting the analysis. Contractors and consultants also provided a wide range of material in support of the assessment.

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[3] U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216.

Finally, OTA convened a series of workshops to clarify important issues to be considered in the assessment and to review and expand upon contractors' analyses.

The first workshop dealt with investment decisionmaking in the electric utility industry. It focused on how the decisionmaking environment is changing in the industry and on identifying the principal considerations by utilities in making new technology investments. In addition, the workshop addressed utility approaches to accommodating nonutility power production, the Federal role in commercialization of new electric power generating technologies, and major policy contingencies that could affect the relative attractiveness of alternative generating technologies over the next several decades. For example, such contingencies as acid rain control policies and increased availability of natural gas for electric power generation were considered.

About midway into the assessment, OTA convened a series of seven workshops dealing with the cost and performance of new generating and load management technologies. These workshops reviewed and refined the benchmark cost and performance figures generated by OTA contractors and identified the most important R&D opportunities necessary for continued advancement of the technologies being considered. The results of these workshops, coupled with the subsequent contractor and OTA staff analyses, formed the basis of the comparative assessment of generating technologies and the likelihood of their contributing significantly to U.S. electric power generation in the next two decades under various policy scenarios.

The final workshop convened in the course of this assessment dealt with economic regulatory issues affecting the development and deployment of new generating technologies. The principal issues addressed were regulatory treatment of research and development by electric utilities, implementation of PURPA, regulation of affiliated electric utility interests involved in new generating technology, and scenarios for deregulating electric power production.

Based on the workshop discussions, advisory panel recommendations, contractor and consultant reports, and OTA staff research, a set of alternative policy options were developed and analyzed. Advisory panel members, workshop participants, contractors, and other contributors to this assessment are listed in the front of this report.

This report is organized as follows:

- Chapter 2 is a summary of the entire report.
- Chapter 3 establishes the context in which electric utility investment decisions are made. In particular, it examines the range of strategic options being considered by utilities and the relative importance of new generating technologies with those options.
- Chapter 4 defines plausible ranges of cost, performance, uncertainty, and risk which are likely to characterize new electric generating and storage technologies in the 1990s. In addition, the prominent R&D needs are identified and discussed.
- Chapter 5 establishes benchmark cost and performance figures for the conventional technologies against which the new technologies are likely to compete over the next two decades. In addition, the prospects for rehabilitating or extending the lives of existing generating facilities and for increased reliance on load management as alternatives to new generating capacity are considered.
- Chapter 6 discusses the impact of decentralized power generation on the performance of electric power systems. The focus is on questions of standards for and costs of interconnecting such sources with the grid as well the effects of increasing penetration of such sources on power system control, operation, and planning.
- Chapter 7 analyzes the differences among U.S. regions that could influence the potential usefulness of new electric generating technologies in those regions. The principal differences include electricity demand growth and peaks, existing fuel use and generating facilities, indigenous energy resources, and interregional transmission capabilities.
- Chapter 8 compares the competitiveness of new technologies with conventional technol-

ogies. In particular, the sensitivity of investments in different technologies to factors such as demand growth, construction lead time, cost and performance, Federal tax policy, and environmental regulation.

- Chapter 9 examines the industry supporting new generating and load management technologies. For each of the technologies considered, the market infrastructure, obstacles to domestic industry development, alternative development paths, and foreign competition are discussed.
- Chapter 10 presents a number of alternative policy options that could affect the development of new electric power generating and load management technologies over the next two decades. The implications of different policy strategies employing these options are discussed.

Chapter 2

Summary

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Chapter 2

Summary

INTRODUCTION

As utilities face the 1990s, the experiences of the 1970s have made them much more wary of the financial risk of guessing wrong and overcommitting to large central station coal and nuclear plants. At the same time, there is growing concern by utilities about the possibility of being unable to meet demand, particularly in view of increased uncertainty about future demand growth. In addition, the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), have made the role of nonutility power producers increasingly important to the future of U.S. electricity supply. As discussed in chapter 1, one of the strategies being pursued by utilities to operate in this new environment is through increased utilization of smaller scale power production by a variety of both conventional and nontraditional energy conversion technologies.

If electricity demand grows at an average annual rate below 2.5 percent through the 1990s (current estimates range from 1 to 5 percent), the need for new generating capacity is likely to be relatively modest. Responses that include life extension and rehabilitation, increased power purchases, and construction of realizable amounts of conventional generation are likely to suffice. But if demand growth should accelerate, these options may not be enough, and the availability of an array of generating technologies that provide a utility with greater flexibility for meeting load requirements may be desirable.

NEW GENERATING TECHNOLOGIES FOR THE 1990s

A number of developing technologies for electric power generation are beginning to show considerable promise as future electricity supply options. Some of these technologies, such as atmospheric fluidized-bed combustion (AFBC) and integrated coal gasification/combined-cycle (IGCC) conversion, and fuel cells, could pave the way for clean and more efficient power generation using domestic coal resources.

In box 2A, the renewable[1] and nonrenewable technologies considered in this assessment are listed and briefly discussed. Table 2-1 shows those technologies grouped according to the sizes and applications in which they would most likely appear if deployed during the 1990s. Also shown in the table are the principal conventional alternatives against which these technologies are most likely to compete. Applications are divided between those in which electrical power output is controlled by the utility (dispatchable) and those where it is not (nondispatchable). Dispatchable applications are further broken down into base, intermediate, and peaking duty cycles. Nondispatchable applications are divided between those with and without storage capabilities.

Many of these technologies **offer modular design features that eventually could allow utilities to add generating capability in small increments with short lead-times and less concentration of financial capital. Other attractive features common to some but not all of these technologies include fewer siting and regulatory barriers, reduced environmental impact, and increased fuel flexibility and diversity**. Virtually all of the technologies considered in this assessment offer the potential of sizable deployment in electric power generation applications beyond the turn of the century. **At the current rate of development, however, most developing technologies will not be in a position to contribute more**

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[1] For purposes of this report we define renewable technologies as those that do not use conventional fossil and nuclear fuels, i.e., solar thermal-electric, photovoltaics, wind turbines, and geothermal. All others we refer to as nonrenewable technologies.

Box 2A.—Developing Technologies Considered in OTA's Analysis

Generating Technologies:

- *Photovoltaics.*—A photovoltaic cell is a thin wafer of semiconductor material which converts sunlight directly into electricity. The cells are grouped into arrays oriented towards the Sun. A photovoltaic installation may consist of any number of arrays, which produce power from a few kilowatts to many megawatts.
- *Solar Thermal-Electric Powerplants.*—These installations convert radiant energy from the Sun into thermal energy, a portion of which subsequently is transformed into electrical energy. The conversion typically employs a generator driven by a turbine.
- *Wind Turbines.*—A wind turbine uses the kinetic energy in wind to rotate a shaft linked to a generator. Wind turbines may be installed alone, or in groups consisting of hundreds of units—so called "windfarms."
- *Geothermal Power Stations.*—Geothermal energy resources are found when geologic anomalies bring heat from the Earth's core close to the surface. A geothermal powerplant taps this energy to drive a turbine-generator. Geothermal heat is brought to the surface occasionally as steam, and used directly to drive a steam turbine. More often, the heat is delivered to the surface in hot water (geothermal brine) and is transferred to a secondary "working fluid" which is subsequently used to drive the turbine. Versions of the latter, binary and dual-flash systems, are emphasized in this study.
- *Fluidized-Bed Combustors.*—A fluidized-bed is a mass or "bed" of small particles through which flow large volumes of combustion gases. The gases move through the bed at velocities sufficient to cause the mass of particles to behave like a fluid; hence the term "fluidized-bed." In a typical fluidized-bed combustor, solid fuel is fed into the bed continuously and mixed with the bed's hot particles. As the fuel burns, the heat is used to generate steam in tubes which lace the bed. The steam, in turn, drives a turbine and generator.
- *Integrated Gasification/Combined-Cycle Powerplant.*—This type of system consists of two basic elements. The first converts a fuel such as coal into a combustible gas. The second is a combined-cycle system in which the gas is burned and used to drive a combustion turbine; after exiting the gas turbine, the hot combustion gases are used to generate steam which drives a steam turbine. The turbines drive generators which produce electricity. The gasification plant and the combined-cycle unit are integrated to use the thermal energy available from the fuel very efficiently.
- *Fuel Cells.*—A fuel cell produces electricity directly by way of an electrochemical reaction of a fuel such as natural gas; neither combustion nor moving parts are required in the conversion process. It can also be integrated with a coal gasifier. Fuel cells are grouped into "stacks," any number of which may be used in a power facility.

Energy Storage Technologies:

- *Batteries.*—In a battery storage plant, one or more batteries are "charged" when electrical energy is converted to potential energy stored by chemicals within the batteries. When the battery is "discharged," reactions within the battery convert the potential energy back into electricity.
- *Compressed-Air Energy Storage (CAES) Facilities.*—In this facility, electric power is used to drive compressors which force air into an underground reservoir. When electricity is needed, the compressed air is released through a combustion chamber and used to drive a turbine and a generator.

Load Management Technologies:

- Load management refers to manipulation of customer demand by economic and/or technical means. This report examines primarily those load management technologies which require utility ownership or control. These consist of devices for measuring and recording information regarding customer power consumption; communications technologies; and technologies which interpret information and automatically effect decisions necessary for effective load management.

Table 2-1.—Selected Alternative Generating and Storage Technologies: Typical Sizes and Applications in the 1990s

Typical configurations in the 1990s

Installation size (MW)	Dispatchable applications[a]			Nondispatchable applications[b]	
	Base load (60-70% CF)	Intermediate load (30-40% CF)	Peaking load (5-15%)	Intermittent (w/o storage)	Others (not utility controlled)
Greater than 250 MWe	Coal gasification/ combined-cycle	Coal gasification/ combined-cycle	n.a.		
	Conventional coal				
51-250 MWe	Geothermal Atmospheric fluidized-bed combustor	Atmosphere fluidized-bed combustor Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (maxi CAES) Solar thermal (w/storage)	Solar thermal Wind	Atmospheric fluidized-bed combustor Solar thermal (w/storage)
	Combined-cycle plants	Combined-cycle plants	Combustion turbine		
1-50 MWE	Geothermal Atmospheric fluidized-bed combustor Fuel cells	Fuel cells Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (mini CAES) Battery storage Fuel cells Solar thermal (w/storage)	Solar thermal Wind Photovoltaics	Atmospheric fluidized-bed combustor Geothermal Fuel cells Solar thermal (w/storage) Battery storage Compressed air storage (mini CAES) Geothermal
			Combustion turbine		Combustion turbine
Less than 1 MWe				Solar thermal Wind Photovoltaics	Fuel cells Battery storage

NOTES: For each unit size and application, new technologies are shown above the dotted line and conventional technologies are shown below the dotted line. CF = capacity factor and n.a. = not applicable.

[a] Dispatchable technologies may not be utility-owned.

[b] Note that nondispatchable technologies may serve base, intermediate, or peaking loads.

SOURCE: Office of Technology Assessment.

than a few percent of total U.S. electric generating capacity in the 1990s, and therefore, will not be of much help in meeting accelerated demand, should it occur.[2]

Cost and Performance

The current cost and performance characteristics (including the uncertainty in both cost and performance) of most new technologies are not generally competitive with conventional alternatives.[3] Cost reductions, performance improvements, and resolution of uncertainties will all occur as these technologies mature. The rate at which this maturity occurs depends on: 1) sustained progress in research, development, and demonstration to reduce cost, improve performance, and reduce uncertainty in both cost and performance; and 2) continued active demonstration of the technologies, particularly in utility applications to develop the commercial operating experience necessary before utility decision-makers will consider a new technology seriously. Utility and nonutility interest in these technologies is also affected by a wide range of other factors relating to environmental benefits, siting requirements, and public acceptance.

Lead-Times

Common to the deployment of all electric generating technologies is the need for planning, design, licensing, permitting, other preconstruction activities, and finally construction itself. These steps with some technologies, for early units at a minimum, may take long periods of time—up to 10 years or more. This means that if those technologies still undergoing development are to be commercially deployed in the 1990s, there may be as little as 5 or 6 years in which to complete development and establish in the minds of investors that their costs, performance, and other attributes fall within acceptable ranges.

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[2] Here and elsewhere in this report, a contribution to U.S. electricity supply is considered "significant" when it amounts to more than 5 to 10 percent of total generating capacity, or the equivalent in terms of electricity storage or reduced demand.

[3] In particular, with conventional generating capacity in smaller unit sizes such as conventional combustion turbines, advanced combined cycle plants, slow-speed diesels, and participation in conventional cogeneration projects.

Specific Generating Technologies

The relative importance of efforts to improve cost and performance versus the need to shorten lead-times in order to attain commercial status varies by technology. This distinction, in particular, makes it convenient to divide the technologies considered here into two basic groups:

1. The first consists of technologies envisioned primarily for direct electric utility applications, and includes IGCC plants; large (>100 MW) AFBC; large (>100 MW) compressed air energy storage (CAES) facilities; large (>50 MW) geothermal plants; utility-owned fuel cell powerplants; and solar thermal central receivers.
2. The second group consists of technologies that are characterized as suitable either for utility or nonutility applications, and includes small (<100 MW) AFBCs in nonutility cogeneration applications; fuel cells small (<100 MW) CAES; small (<50 MW) geothermal plants; batteries; wind; and direct solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

In both groups, the goal of research, development, and demonstration is to improve cost and performance characteristics to a point where the technologies are commercially competitive. For the first group of technologies, however, the likelihood of long lead-times for early commercial units is the primary constraint to extensive use in the 1990s. Technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. For most of them to make a significant contribution in the 1990s, however, their research, development, and demonstration will have to be stepped-up in order to reduce cost to levels acceptable to utility decisionmakers and nonutility investors, and resolve cost and performance uncertainties.

It is important to note that the distinction between these two groups of technologies is not rigid. Technologies in the first group also could benefit from accelerated research and development while those in the second group could be held back by long lead-times.

In addition, many of the technologies in the second group are small enough to qualify as small power producers employed in nonutility power generating projects operating under the provisions of PURPA. **The existence of a wide variety of markets and interested investors outside the electric utilities increases the likelihood that at least some of these technologies will be deployed**.

Because of its modular nature and positive environmental features, the IGCC has the potential for deployment lead-times of no more than 5 to 6 years. Early commercial units, however, may require longer times—up to 10 years—because of regulatory delays, construction problems, and operational difficulties associated with any new, complex technology; and it may take a number of commercial plants before the short lead-time potential of the IGCC is realized. In addition, despite the success of the Cool Water demonstration project, a 100 MWe IGCC plant that has increased electric utility confidence in the technology, more operating experience is likely to be required before there will be major commitment to the IGCC by a cautious electric utility industry. Therefore, **unless strong steps are taken to work closely with regulators and to assure quality construction for these initial plants, there may be insufficient time remaining after utilities finally make a large commitment to the IGCC for the technology to make a significant contribution before 2000**. As has been shown in the Cool Water project, though, such steps are possible, and they may be facilitated if initial commercial units are in the 200 to 300 MWe range rather than the current design target of 500 MWe.

The first large (about 150 MW), "grass-roots" (i.e., not retrofits of existing facilities) AFBC installations for generating electricity also may be subject to long lead-times. Moreover, a large AFBC demonstration unit probably will not even be operating until 1989. It now appears unlikely that the operation of that unit will be sufficient to justify large numbers of orders within the first few years of the 1990s. The AFBC, however, also has the potential for needing lead-times on the order of only 5 years. Further, favorable experience with smaller AFBC cogeneration units and AFBC retrofit units which will be in service by 1990 may provide the commercial experience needed to accelerate deployment of the larger units.

Foremost among new technologies offering the potential of significant deployment in the 1990s are small (below 100 MWe) AFBC plants in cogeneration applications and larger (100 to 200 MWe) AFBC retrofits to existing coal-fired powerplants. By 1990, plants of both types will be operating. Over a dozen commercial cogeneration plants using AFBC have been started by nonutilities, and two large utility retrofit projects are underway. These first plants appear capable of producing electricity at lower costs than their solid-fuel burning competitors (including the IGCC and large, electric-only, grass-roots AFBCs) in the 1990s. The prospects are good that additional orders—perhaps mostly from nonutilities—will be forthcoming and that large numbers of these AFBC units could be operating by the end of the century.

While the prospects for wind turbines are clouded by the anticipated termination of the Renewable Energy Tax Credits (RTC) and other potential tax changes, the outlook nevertheless appears promising. By the end of 1984, an estimated 650 MWe were in place in wind farms in the United States, mostly in California (550 MWe). Over the early 1980s, capital costs have dropped rapidly and performance improved swiftly. **Improvements are expected to continue, and the cost of electric power from wind turbines, even unsubsidized ones, in high-wind parts of the country may soon be considerably lower than power from many of their competitors**. The rate of improvement will be heavily influenced by future trends in the avoided costs or "buy-back rates" offered by utilities to nonutility electricity producers. Should these costs be low or uncertain, technological development and application will be slowed. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins of generating capacity, might considerably accelerate their contribution.

Although geothermal development has been substantial compared to other technologies, most of this development has occurred at The Geysers in California, an unusual high-quality dry steam resource (one of only seven known in the world) that can be tapped with mature technology. All other geothermal resources in the United States require less developed technology to generate power. Two developing geothermal technologies, though, are currently being demonstrated on a small scale and show promise for commercial applications in the West. Current evidence indicates that these technologies—dual flash and binary systems—are very close to being commercial, and that cost and performance will be competitive. Small binary units (about 10 MWe) are already being deployed commercially. These developments, coupled with the fact that the technologies can be put in place with lead-times of 5 years or less, suggest that they could produce considerable electric power in the West by the end of the century. As is the case with wind power, **the growth rate of geothermal power will be sensitive to Federal and State tax policy**.

Initial commercial application of fuel cells should appear in the early 1990s, primarily fired with natural gas. The large and potentially varied market (it includes both gas and electric utilities as well as cogenerators), the very short lead-times, factory fabrication of components, and a variety of operational and environmental benefits all suggest that when cost and performance of fuel cell powerplants become acceptable, deployment could proceed rapidly. **The principal obstacle to fuel cells making a significant contribution seems to be insufficient initial demand to justify their mass production.** For such demand to appear in the 1990s, extensive commercial demonstration in the late 1980s will probably be necessary.

The development rate of photovoltaics (PV) has been considerable in recent years, but the technical challenge of developing a PV module

that is efficient, long-lasting, and inexpensive remains. While technical progress and deployment of photovoltaics in the United States are likely to be slowed by termination of the RTC or by other changes in Federal or State tax law, or by declining avoided costs, industry activity is likely to remain intense. Aided by interim markets of specialized applications and consumer electronics, PVs could develop to the point where competitive grid-connected applications at least begin to appear in the 1990s. In the 1990s, overseas markets may dominate the industry's attention, stimulating and supporting improvements in cost and performance, and encouraging mass production to further reduce costs. However, European and Japanese vendors, assisted by their respective governments, have been more successful than U.S. vendors in developing these markets. Foreign competition is likely to be a major concern for U.S. vendors over the next decade.

Of the solar thermal technologies, solar parabolic dish technologies offer the most promise over the next 10 to 15 years; although with current uncertainty in cost and performance, solar troughs may be competitive as well. Characteristics of some solar dish and trough designs indicate that they could be rapidly put in place in areas such as the Southwest. The cost of power generation using these designs in such regions could be very close to those of conventional alternatives. Some demonstration and subsidized commercial units already are operating. **Full commercial application, however, will require further demonstrations of the technologies over extended periods of time; such demonstrations must be started no later than 1990 if the technologies are to be considered seriously by investors in the 1990s**. The likelihood of such demonstrations appears now to depend on the availability of some kind of subsidy. In particular, **development of the technology to date has depended heavily on the RTC**.

Other solar thermal technologies, including central receivers and solar ponds, while showing long-term promise, are unlikely to be competitive with other electric generating alternatives or have sufficient commercial demonstration experience to yield any significant contribution through the 1990s. The central receiver, however, is of continuing interest to a some Southwestern utilities in the long term because it offers a favorable combination of advantages including the potential for repowering applications, high efficiency, and storage capabilities.

Along with new generating technologies, this assessment examined two electric energy storage technologies—compressed air energy storage (CAES) and batteries—that show long-term promise in electric utility applications.

Because of potentially long lead-times, CAES appears to have only limited prospects in the 1990s. The large-scale (>100 MW) version of this technology (called maxi-CAES) currently has an estimated lead-time of 5 to 8 years; of this, licensing and permitting and other preconstruction activities is expected to take 2 to 4 years. Moreover, while commercial installations are operating in Europe, no plant yet exists in the United States. Despite strong evidence that this technology offers an economic storage option, CAES is unlikely to be the target of much investment until a demonstration plant is built. No plans for a demonstration plant currently exist. Further, while a demonstration project should prove the technology, the peculiar underground siting problems and unfamiliarity with the CAES concept may still limit early application.

A smaller alternative—mini-CAES (<100 MW)—promises to have a much shorter lead-time due to modularity of the above-ground facilities and short (30-month) construction lead-times. Here too, however, unless a demonstration plant is started in the next few years, extensive deployment before the end of the century is improbable.

Resolution of a variety of cost and performance uncertainties remains before extensive use of advanced battery storage systems can be anticipated. If the technical problems can be resolved in a timely fashion and demonstration programs are successful, however, rapid deployment in electric utility applications could occur, due to the short lead-times and cost reductions associated with mass production. Of the candidates, lead-acid and zinc-halogen batteries appear to show the most promise.

Table 2-2 summarizes the most promising areas of research and development identified by OTA for the technologies analyzed in this assessment. Atention to these research and development opportunities could accelerate commercial their development through the 1990s. Table 2-3 summarizes the major electric power generating projects utilizing these technologies installed or under construction as of May 1985.

CONVENTIONAL ALTERNATIVES IN THE 1990s

The contribution of developing technologies over the next two decades depends in part on the relative cost and performance of conventional generating options as well as a variety of options for extending the lives or otherwise improving the performance of existing generating facilities.

New Capacity

To the extent that new generating capacity is needed at all over the next two decades, conventional pulverized coal plants, combustion turbines, and advanced combined-cycle plants will continue to be the principal benchmark against which utilities and others will compare developing generating technologies. Utilities are very interested, however, in smaller unit sizes of even these technologies. Also, if nuclear power is to become a realizable choice again for utilities, it is likely to involve smaller, standardized units.

If hydroelectric opportunities are available, they are likely to be exploited in both run-of-river and pumped storage applications; few new hydroelectric opportunities, though, are likely through the 1990s. Similarly, refuse steam plants, biomass technologies (e.g., wood waste-fired power generation), slow-speed diesels, and vapor-dominated geothermal plants all use mature technologies so that where opportunities exist, they are likely to be chosen over newer technologies.

In addition, enhancements to conventional plants such as limestone injection in coal boilers, coal-water fuel mixtures, and others will all be reviewed carefully along with new generating technologies as utilities plan for new capacity. The availability of such enhancements could significantly affect the relative attractiveness of new technologies in the 1990s.

Plant Betterment

By 1995, the U.S. fossil steam capacity will have aged to the point where over a quarter of the coal and nearly half of the oil and gas steam units nationwide will be over 30 years old. In the past, the benefits of new technology often outweighed the benefits of extending the useful lives of existing generating facilities, rehabilitating such facilities to improve performance or upgrade capacity, or even repowering such plants with alternative fuels. All of these so-called plant betterment options are receiving renewed interest by utilities because plants "reaching their 30th birthday" over the next decade have attractive unit sizes (100 MW or larger) and performance (heat rates close to 10,000 Btu/kWh). For that reason, **rehabilitating or simply extending the lives of such units, frequently at much lower anticipated capital costs than that of new capacity, are often very attractive options for many utilities**. Prospects are particularly bright if units are located at sites close to load centers and the rehabilitation does not trigger application of New Source Performance Standards, i.e., more stringent air pollution controls.

In many instances, plant betterment can also improve efficiency up to 5 to 10 percent and/or upgrade capacity. Additional benefits from such projects include possible improvements in fuel flexibility or reduced emissions of existing generating units at modest cost relative to that of new capacity. Finally, an initial market for some new technologies such as the AFBC are in repowering applications, e.g., where an existing pulverized coal plant is retrofitted with an AFBC boiler.

Load Management

Load management refers to manipulation of customer demand by economic and/or techni-

Table 2-2.—Areas of Principal Research Opportunities: Developing Technolgies for the 1990s

Wind:

1. Development of aerodynamic prediction codes
2. Development of structural dynamic codes
3. Fatigue research
4. Wind-farm wake effects
5. Development of acoustic prediction codes

Solar thermal electric:

General:

1. Low cost, reliable tracking hardware

Solar ponds:

1. Physics and chemistry
2. Design and performance analysis
3. Construction techniques
4. Operation and maintenance

Central receivers:

1. Physics and chemistry
2. Development and long-term testing of cheap and durable scaled-up molten-salt subsystems (including receiver, pumps, valves, and pipes)

Parabolic dishes:

1. Durable engines
2. Cheap, high-quality, durable reflective materials (polymers)
3. Long-life Stirling and Brayton heat engines

Parabolic troughs:

1. Inexpensive, long-lived, high-temperature thermal-storage media
2. Cheap, leak-resistant, well-insulated receiver-tubes
3. Cheap, high-quality, durable reflective materials (polymers)

Photovoltaics:

1. Highly efficient, long-lived, mass-produced cells; especially those suitable for use with concentrators
2. Cheap semiconductor-grade silicon
3. Cheap, durable, and reliable modules and module subcomponents (especially the optics and cell mounts for concentrator modules)
4. Reliable, inexpensive and durable "balance of systems," especially tracking systems and power conditioners

Fluidized-bed combustors:

Circulating-bed AFBCs:

1. Cheap, durable, and reliable equipment for separating solids from gas streat
2. Erosion- and corrosion-resistant materials and designs

Bubbling-bed AFBCs:

1. Adequate sulfur capture by limestone sorbent
2. Effective fuel-feed systems
3. Erosion- and corrosion-resistant materials and designs

Integrated gasification/combined-cycle:

1. Cheap, durable, reliable, and efficient combustion turbines and combined-cycle systems
2. Erosion- and corrosion-resistant materials
3. Gasifiers capable of effectively converting a variety of fuels
4. Design-specific research requirements:
    - a. Moving-bed gasifiers: full utilization of fines and hydrocarbon liquids
    - b. Fluidized-bed gasifiers: full carbon conversion
    - c. Entrained flow gasifiers: raw gas cooling without excessive corrosion or ash entrainment

Energy storage:

Batteries:

1. Cheap, highly active, and long-lived (especially corrosion-resistant) catalysts
2. Corrosion-resistant structural materials
3. Low-cost and long-lasting electrolytes

Compressed-air energy storage:

1. Corrosion-resistant equipment (especially turbine blades and underground equipment)
2. Durable, reliable, and inexpensive recuperator (recuperator discharges heat from combustion turbine gases to incoming compressed air)
3. Lower cost of existing underground storage sites
4. Improved recovery of compression heat
5. Geologic response to air cycling in reservoir

Load management technologies:

Meters:

1. Mass-produced, inexpensive, durable, reliable solid-state devices capable of operating in adverse environments
2. Meter capable of sustaining operation during power outages

Communications systems:

1. Inexpensive, reliable, and durable residential receivers or transponders

Logic systems:

1. Development of appropriate software

Fuel cells:

1. Lower cost and more efficient catalysts
2. Less corrosive and temperature-sensitive structural materials
3. Higher power densities via:
    - a. Improved coolig systems
    - b. Improved oxygen flows
    - c. Improved cell geometry
4. More stable electrolytes
5. Longer stack life

Geothermal:

1. Inexpensive, durable, and reliable down-hole pumps
2. Detailed resource assessment
3. Inexpensive, durable, and reliable well casing materials

Dual flash:

1. Cheap, durable, and reliable equipment for removing noncondensable gases and/or entrained solids from brines
2. Reliable operation in highly saline environments

Binary:

1. Inexpensive, durable working fluids
2. Equipment durability and reliability in highly saline environments

SOURCE: Office of Technology Assessment

Table 2-3.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985

Technology	Capacity	Location	Primary sources of funds	Status
Wind turbines[a]	550+ MWe (gross)[b]	California wind farms	Nonutility	Installed
	100+ MWe (gross)[c]	U.S. wind farms outside of California	Nonutility	Installed
	? MWe[d]	All U.S. wind farms	Nonutility	Under construction (1986)
Solar thermal electric:				
Central receiver	10 MWe (net)[e]	Daggett, CA	Utility, nonutility, and Government	Installed
	0.75 MWe	Albuquerque, NM	Utility, nonutility, and Government	Installed
Parabolic trough	14 MWe (net)	Daggett, CA	Nonutility	Installed
	30 MWe (net)	Daggett, CA	Nonutility	Under construction (1986)
Parabolic dish	0.025 MWe (net)[f]	Palm Springs, CA	Government	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Under construction
	3.6 MWe	Warner Springs, CA	Nonutility	Installed
Solar pond	None			
Photovoltaics:				
Flat plate	1 MWe (dc, gross)	Sacramento	Utility and Government	Installed
	1 MWe (dc, gross)	Sacramento, CA	Utility and Government	Under construction (1985)
	1 MWe (dc, gross)	Hesperia, CA	Nonutility	Installed
	6.5 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Installed
	0.75 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Under construction
Concentrator	4.5 MWe (dc, gross)	Borrego Springs, CA	Nonutility	Installed[g]
	1.5 MWe (dc, gross)	Davis, CA	Nonutility	Installed[g]
	3.5 MWe (dc, gross)	Barstow, CA	Nonutility	Installed[g]
Geothermal:				
Dual flash	10 MWe	Brawley, CA	Utility/nonutility	Installed
	10 MWe	Salton Sea, CA	Utility/nonutility	Installed
	47 MWe (net)	Heber, CA	Nonutility	Under construction (1985)
	32 MWe (net)	Salton Sea, CA	Nonutility	Under construction (1985)
Binary:				
Small	2 × 3.5 MWe	Mammoth, CA	Nonutility	Installed
	3 × 0.3 MWe	Hammersly Canyon, OR	Nonutility	Installed
	3 × 0.4 MWe	Hammersly Canyon, OR	Nonutility	Installed[h]
	10 MWe	East Mesa, CA	Nonutility	Installed
	1 × 0.75 MWe (gross)	Wabuska, NV	Nonutility	Installed
	3 × 0.35 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	3 × 0.45 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	4 × 1.25 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
	3 × 0.85 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
Large	45 MWe (net)	Heber, CA	Utility, nonutility, and Government	Installed
Fuel cells:				
Large	None			
Small[j]	38 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Installed
Small[j]	5 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Under construction
Fluidized-bed combustors:				
Large grass roots	160 MWe	Paducah,KY	Utility[k] and Government	Under construction (1989)
Large retrofit	100 MWe	Nucla, CO	Utility[k]	Under construction (1987)
	125 MWe	Burnsville, MN	Utility[k]	Under construction (1986)
	125 MWe	Brookesville, FL	Nonutility	Under construction (1986)
Small cogeneration	30 MWe	Colton, CA	Nonutility	Under construction (1985)
	25 MWe	Fort Wayne, IN	Nonutility	Under construction (1986)
	15 MWe	Ione, CA	Nonutility	Under construction (1987)
	67 MWe	Chester, PA	Nonutility	Under construction (1986)

[a] Includes small- and medium-sized wind turbines.

[b] Approximately 550 MWe were operating in California at the end of 1984. It is not known how much additional capacity was installed by May 1985.

[c] Approximately 100 MWe were operating outside of California at the end of 1984. It is not known how much additional capacity had been installed outside California by May 1985.

[d] It is not known how much capacity was under construction on May 1, 1985.

[e] This facility, the Solar One Pilot plant, is not a commercial-scale plant and differs in other important ways from the type of system which might be deployed commercially in the 1990s.

[f] This installation consists of only one electricity producing module; a commercial installation probably would consist of hundreds of modules.

[g] Only 10 percent of the modules were operating at the time because of problems with the power conversion systems.

[h] Installed but not operating, pending contractural negotiations with utilities.

[i] The equipment modules have been delivered to the site; site preparation, however, has not started.

[j] These units are not commercial-scale units.

[k] Including the Electric Power Research Institute.

Table 2-3.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985—Continued

Technology	Capacity	Location	Primary sources of funds	Status
	90 MWe[l]	Decatur, IL	Nonutility	Under construction (1986)
	50 MWe[m]	Cedar Rapids, IA	Nonutility	Under construction (1987)
	3.5 MWe	Pekin, IL	Nonutility and Government	Installed
	28 MWe	Pontiac, MI	Nonutility	Under construction (1986)
	2.8 MWe	Washington, DC	Nonutility and Government	Installed
	24 MWe	Enfield, ME	Nonutility	Under construction (1986)
	20 MWe	Chinese Station, CA	Nonutility	Under construction (1986)
IGCC[n]	100 MWe	Daggett, CA	Utility, nonutility, and Government	Installed
Batteries:				
Lead acid[o]	0.5 MWe	Newark, NJ	Utility and Government	Installed
Zinc chloride	None[p]			
CAES:				
Mini	None			
Maxi	None			

[l] This is the total capacity which may be generated from the four AFBC boilers which will be installed.
[m] This is the total capacity which may be generated from the two AFBC boilers which will be installed.
[n] While this installation, the Cool Water unit, uses commercial-scale components, the installation itself is not a commercial-scale installation.
[o] While this installation at the Battery Energy Storage Test Facility uses a commercial-scale battery module, the installation itself is not a commercial-scale installation.
[p] A 0.5-MWe zinc chloride commercial-scale battery module was, however, operating at the Battery Energy Storage Test facility until early 1985.

SOURCE: Office of Technology Assessment

cal means. It is done for the mutual benefit of both utility and customer, usually as a means to provide maximum productivity of the utility's generation and distribution capacity. While load management is not a permanent substitute for new capacity, it can enable a given capacity to satisfy a greater customer base, and operate at maximum efficiency. It is now employed by some utilities and being seriously considered by many others to improve their load factor—the ratio of average to peak load. Since base load generating equipment is generally more thermally efficient than peak load equipment, one of the principal goals of load management is to encourage a shift of demand to off-peak periods. The other is to defer the need for costly new generating capacity by inhibiting demand during peak periods. This assessment focuses on technology-based direct load control technologies employing advanced meters and utility-owned or controlled load control systems. A potentially important feature of load management is that it can help reduce future demand growth uncertainty if the saturation and use of load management devices can be more accurately predicted. If such predictions are not possible, however, then increased load management may actually increase demand uncertainty.

Based on the results of current load management programs and ongoing experiments, load management technologies are expected to be able to be deployed at costs below those associated with many conventional generating alternatives. In many instances, however, these costs cannot be reached without substantial utility demand to encourage manufacturers to realize volume production economies.

Widespread deployment of load management in the 1990s will depend on continued experimentation by utilities to resolve operational uncertainties; the refinement of load management equipment and techniques, including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer acceptance. Commitments to initiate load management systems will also depend on the nature of a utility's demand patterns and capacity mix, the attitudes of utility decisionmakers, and on public utility commission actions. The degree of public utility commission support, in particular, is likely to be very important over the next decade.

IMPACT OF DISPERSED GENERATING TECHNOLOGIES ON SYSTEM OPERATION

As the participation in U.S. electric power systems of nonutility owned and operated dispersed generating sources (DSGs) increases, the implications for system operation, performance, and reliability are receiving increased attention by the industry. **For the most part, however, the technical aspects of interconnection and integration with the grid are fairly well understood and most utilities feel that the technical problems can be resolved with little difficulty**. State-of-the-art power conditioners are expected to alleviate utility concerns about the quality of interconnection subsystems. A number of nontechnical problems remain, though, which could inhibit the growth of DSGs.

Nonutility Interconnection Standards

More utilities are developing guidelines for interconnection of DSGs with the grid. A number of national "model" guidelines are being developed by standard-setting committees for the Institute of Electrical and Electronic Engineers, the National Electric Code, the U.S. Department of Energy, and the Electric Power Research Institute, although none has yet released final versions and widespread utility endorsement is still uncertain. As a result, **DSG owners are likely to face different and sometimes conflicting interconnection equipment standards well into the 1990s. These differences may hamper both the use of DSGs as well as the standardized manufacture of interconnection equipment**.

Interconnection Costs

The costs of interconnection have declined dramatically in recent years, particularly for smaller DSGs. Typical costs range from $600/kW for 5 kW units to less than $100/kW for 500 kW or larger units. The interconnection costs for multimegawatt DSGs are only a small fraction of the total cost of the facility. While future technological advances in microprocessor controls and less costly nonmetallic construction could bring costs down even further, the major cost decrease is expected to come from volume production of equipment. As mentioned above, though, this volume production may be delayed until national model interconnection guidelines are agreed on for interconnection equipment.

REGIONAL DIFFERENCES

A particularly important factor affecting the relative advantages of new electric generating, storage, and load management technologies is the region in which a utility or prospective nonutility power producer is located. U.S. regions differ markedly in industrial base, demographic trends, and other factors affecting electricity demand; the age and composition (particularly fuel use) of existing generating facilities; the nature and magnitude of available indigenous energy resources; regulatory environment; transmission infrastructure and prospects for bulk power transfers; and other factors affecting the selection of electric power technologies.

Existing Generation Mix

The regional mix of existing generating facilities is likely to profoundly affect the relative attractiveness of new generating capacity. While most electric utility systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, **reliance on these fuels is expected to be strong enough in some areas, i.e., New England, the Gulf and Mid-Atlantic States, the Southeast, and the West, that the economics of competing technologies will remain particularly sensitive to the price and availability of oil and gas**. This will apply even more strongly in the few States such as Florida where, due to expectations of high demand growth and continued decreases in (or stabilization of) oil prices, utility systems are actually forecasting increased use of oil.

In California oil- and gas-fired generation, while declining, is projected to remain above 33 percent of the total electricity generation in the State through the end of the century (oil alone will be 15 percent). Similarly, if present trends continue in Texas, oil and gas is projected to account for 35 percent of total generation and about 50 percent of total capacity over the same time period. In both States, high avoided cost rates resulting from continued reliance on oil and gas enhances the attractiveness of cogeneration, in particular, while the favorable tax climate in California enhances the attractiveness of renewable power generation projects initiated under PURPA. **In some States where oil and gas are the dominant fuels, especially California, Louisiana, and Texas, cogeneration may constitute a significant fraction of total installed capacity by the end of the century**. Some utilities in Texas, for example, are already planning for cogeneration contributions of as much as 30 percent.

The age of existing power generating facilities varies widely among U.S. regions. As a result, the prospects for life extension and plant rehabilitation vary as well. For example, Texas, the Southeast, and the States west of the Rockies will have the highest percentage increases in plants that would be logical candidates for such options between now and 1995, i.e., those generating units that will have been in operation more than 30 years. In terms of total installed capacity, the opportunities for life extension will be greatest in the Mid-Atlantic, Southeast, Gulf, and Western States. Site-specific economics will determine actual implementation levels.

Interregional Bulk Power Transactions

It appears that existing interutility and interregional transmission capabilities are being nearly fully utilized in the United States. Hence, the prospects for large increases in bulk power purchases among utilities using existing transmission capabilities will be limited. **Some regions,** however, such as portions of the West and Midwest, **are continuing to expand generation and transmission facilities in anticipation of serving the bulk power markets**. In addition, major transmission projects are underway in New York, New England, the upper Midwest, and the Pacific Northwest to allow these regions to purchase lower cost hydroelectric power generated in Canada from existing and proposed facilities.

Load Management

OTA has found that the prospects for increased load management in future utility resource planning vary by region. Perhaps more importantly, they also vary significantly by utility within reliability council regions. Moreover, utilities' objectives for pursuing load management vary as well. For example, utilities with very high current or anticipated reserve margins (many in the Midwest), are interested in load management to better use existing base load capacity, i.e., to stimulate increased demand in off-peak periods. Other utilities with very low current or anticipated reserve margins are pursuing load management primarily to reduce peak demand and defer the need for new capacity additions. Municipal utilities and rural cooperatives, which accounted for most of the points controlled by load management in 1983, are expected to continue to provide a strong load management market in all regions through the 1990s.

Reliability Criteria

An important indicator of a region's need for new generating capacity is reflected in measures of projected power system reliability. Such measures include the reserve margin—i.e., amount of installed capacity available in excess of the peak load, traditionally expressed as a percentage of the total installed capacity. Reserve margins, as well as other reliability measures, are sensitive to demand predictions, scheduled capacity additions and retirements, and other factors such as scheduled maintenance and adjustments for forced outages or firm power purchases and sales from other utilities.

The anticipated reserve margins over the next several decades vary considerably by region. Under medium demand growth (2.5 percent average annual growth through 1995), reserve margins are expected to dip as low as 15 percent (in the upper Midwest in the early 1990s) and peak as high as 47 percent (in the West in the mid-1980s). Under higher demand growth, power pools in all regions may fall below acceptable reliability levels in the early 1990s. Under low demand growth (less than 2 percent), reliability levels are likely to be adequate in all regions through the early 1990s.

Renewable Resources

Increased use of solar, wind, and geothermal resources in U.S. electric power generation will vary regionally due to both the relative cost of alternative generation and the availability of high-quality renewable resources. For example, while wind regimes are promising for wind turbines in many areas across the country, they are currently being developed mostly in California where high utility avoided cost and a favorable tax climate have encouraged their development in nonutility power production applications under PURPA. In addition, a State-sponsored wind resource assessment program has spurred development. A similar situation exists for photovoltaics and geothermal power, although geothermal development is much more regionally limited to the West. Solar thermal power generation, for the next several decades at least, may be viable only in the Southwest and perhaps the Southeast where solar insolation characteristics may be sufficient to make projects competitive and where land availability is not a major constraint on development.

UTILITY AND NONUTILITY INVESTMENT DECISIONS

Prior to the 1970s, maintaining power system reliability was treated as a prescribed constraint and utilities had little difficulty earning their regulated rate of return on investment while achieving steady reductions in the cost of electricity by building larger, less capital-intensive powerplants. Hence, utility decisionmaking objectives of maintaining service reliability, maximizing corporate financial health, and minimizing rates could generally be pursued simultaneously.

Because of the complex and uncertain investment decision environment that has evolved since the 1970s, utilities have begun to consider offering varying levels of service reliability and to more sharply weigh trade-offs between stockholders' and ratepayers' interests in making new plant investment decisions. **In many instances, utilities are avoiding making large-scale plant commitments and, indeed, are considering the host of options cited earlier that can defer the need for such commitments.**

Utility Investment

Of particular interest to many utilities are the potential benefits of increased planning flexibility and financial performance offered by small-scale, short lead-time generating plants. For example, **OTA modeling studies indicate that with uncertain demand growth, the cash flow benefits of such plants can be considerable.** This is true, in some cases, even when the capital cost per kilowatt of the smaller plants is as much as 10 percent more than for large plants. In addition, the corresponding revenue requirement under a small plant scenario can be lower over a 30-year period.

Electric utility efforts to exploit these financial benefits and nonutility interest in exploiting potentially attractive investment opportunities under PURPA have already stimulated considerable interest from both types of investors in smaller scale generating technologies. **Other benefits are important as well, including less environmental impact, less "rate shock" to consumers by adding generating units to the rate base in smaller increments, increased fuel diversity, and reduced transmission requirements if generating units can be sited closer to load centers.**

Most of the generating technologies considered in this assessment offer the small-scale modular features attractive to many utilities as a means of coping with financial and demand uncertainties. This is likely to make the long-term prospects of these technologies very bright. **Despite this long-term promise, however, in most regions for the next 10 to 15 years most of the new generating technologies are not likely to be competitive with other often more cost-effective strategic options cited earlier**—life extension and rehabilitation of existing generating facilities, increased purchases of power from other systems, and intensified conservation and load management efforts.

Nonutility Investment

Nonutility interest is likely to continue to be limited for the most part to more mature technologies that can be implemented in cogeneration applications or can qualify for favorable tax treatment, e.g., combustion turbines, wind, and more recently AFBC.

Investors in nonutility power projects seek to maximize the risk-adjusted return on their invested capital. Depending on the type of investor, other considerations are important as well including tax status, timing of the investment, cash flow patterns, and maintenance of a balanced portfolio of investments with varying risk. In order to finance a new nonutility project, the major risks (technology, resource, energy price, and political) must either by mitigated or incorporated in contingency plans. Common risk reduction techniques used to date include vendor guarantees (or having the equipment vendor take an equity position in the prospective venture) or take-or-pay contracts with utilities.

CURRENT AND FUTURE STATE OF ALTERNATIVE TECHNOLOGY INDUSTRY

Many of the new generating technologies considered in this assessment are being developed by a much wider range of firms than has traditionally dealt with the electric utility industry. Moreover, many firms involved in deploying some new technologies, to the extent that they are being deployed, are small independent firms, less than 3 years old. For example, the wind industry's equipment sales have for the most part been to third-party financed wind parks selling power to utilities under PURPA; many of these parks have been developed by the wind manufacturers themselves. Other developers are large aerospace, petroleum, or other companies that have also not traditionally dealt with electric utilities, and many of them are only beginning to develop working business relationships with them.

Most of the technologies considered in this assessment are in a transition phase of their development, i.e., between pilot- and commercial-scale demonstrations or early commercial units. Some of these technologies are progressing through this transition aided by the existence of auxiliary markets (in many cases foreign) other than the grid-connected power generation market. For example, small-scale AFBC technology has matured in the industrial marketplace, primarily in process heat applications. Similarly, while the PV technology that will ultimately begin to penetrate grid-connected power generation markets is not yet clear, the various candidates (flat plate, amorphous silicon, concentrators, etc.) are maturing in other markets such as consumer electronics or remote power applications.

As most of these technologies mature and the relationships of vendors and manufacturers with utilities and nonutility power producers develop, the nature of negotiated agreements between the parties initiating commercial demonstrations or early commercial units may dictate the pace of commercial deployment of the technologies. In particular, **the allocation of risks in the form of performance or price guarantees or other mechanisms will be especially important for the electric utility market**. For example, an equipment manufacturer's agreement to hold an equity position in early commercial projects might be viewed by many utilities as an adequate performance guarantee.

One of the problems facing increased deployment of some new generating technologies in the

1990s, as mentioned earlier, was that of potential delays in lead-times of early commercial projects. While the features of smaller scale and modular design for many of these technologies offer ultimate promise for very short lead-times, **experience to date indicates that the rate of deployment of some new generating technologies is being lowered because lead-times being experienced by early commercial projects have been longer than anticipated, partially due to the time needed to complete regulatory reviews**. As regulatory agencies become more familiar with the technologies, the time to complete such reviews should decrease, although this is by no means guaranteed as evidenced by the history of other generating technologies.

The pressures of competition from foreign vendors, many of whom are heavily supported by their governments, as well as the current lack of U.S. demand for some of these new technologies in grid-connected power generation applications, and the pending changes in favorable tax treatment throw into doubt the continued commitment of U.S. firms who are currently developing these technologies. For some technologies, such as wind turbines, solar thermal-electric technologies, and photovoltaics (at least those focusing on concentrator technologies), the survival of some domestic firms may be at stake. Many domestic firms may not be able to compete in world markets over the next decade. However, in some cases foreign markets are considered to be interim markets for technologies as they mature to the point where they can compete in the U.S. grid-connected power generation market.

FEDERAL POLICY OPTIONS

Accelerated demand growth, coupled with current problems in building conventional, central station powerplants, could lead to serious difficulty in meeting new demand in the 1990s. **As a result it may be prudent to ensure the availability of an array of new generating technologies**. Then, the buyers in the market for generating technologies will have a broader range of technologies from which to choose. To ensure this **availability** will probably require a sustained Federal involvement in the commercialization of new electric power generating, storage, and load management technologies. The most logical goals for the Federal initiatives are:

- reduce capital cost and performance uncertainty,
- encourage utility involvement in developing technologies,
- encourage nonutility role in commercializing developing technologies, and
- resolve concerns regarding impact of decentralized generating sources (and load management) on power system operation.

The first three are primary goals while the fourth is less critical although still important. The relative importance of these goals as well as the efforts to achieve them are at the center of the debate over future U.S. electricity policy. A range of possible initiatives is summarized in table 2-4 along with the Federal actions that would most likely be required to implement them.

Research, Development, and Demonstration

Perhaps foremost among the options necessary to accelerate technology development is a sustained Federal presence in research, development, and demonstration of new electric generating and load management technologies. While **most of these technologies are no longer in the basic research phase, development hurdles are still formidable and the importance of research, development, and demonstration remains high; if these hurdles are overcome the result could be a quick change in competitive position for many of these technologies**. For example, proof of satisfactory reliability during a commercial utility-scale demonstration of AFBC could substantially accelerate its deployment among electric utilities. As noted, the technology already is beginning to be deployed very quickly in smaller scale commercial cogeneration applications.

Table 2-4.—Policy Goals and Options

Reduce capital cost, improve performance, and resolve uncertainty:

1. Increase Federal support of technology demonstration
2. Shorten project lead-times and direct R&D to near-term commercial potential
3. Increase assistance to vendors marketing developing technologies in foreign countries
4. Increase resource assessment efforts for renewable energy and CAES resources (wind, solar, geothermal, and CAES-geology)
5. Improve collection, distribution, and analysis of information

Encourage nonutility role in commercializing developing technologies:

1. Continue favorable tax policy
2. Improve nonutility access to transmission capacity
3. Develop clearly defined and/or preferential avoided energy cost calculations under PURPA
4. Standardize interconnection requirements

Encourage increased utility involvement in developing technologies:

1. Increase utility and public utility commission support of research, development, and demonstration activities
2. Promote involvement of utility subsidiaries in new technology development.
3. Resolve siting and permitting questions for developing technologies
4. Other legislative initiatives: PIFUA, PURPA, and deregulation

Resolve concerns regarding impact of decentralized generating sources on power system operation:

1. Increase research on impacts at varying levels of penetration
2. Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

SOURCE: Office of Technology Assessment.

A critical milestone in utility or nonutility power producer acceptance of new technology is completion of a successful commercial demonstration program. The utility decisionmaking caution cited earlier confers added importance to advanced commercial demonstration projects. While there is considerable debate in the industry over what constitutes an adequate demonstration, two basic categories are often distinguished: One is a proof-of-concept phase which provides the basic operational data for commercial designs as well as test facilities designed to prove the viability of the technology under nonlaboratory conditions and to reduce cost and performance uncertainties. The other involves multiple applications of a more or less mature technology designed to stimulate commercial adoption of the technology. Generally, activities in the first category are necessary for demonstrating commercial viability and activities in the second category are necessary for accelerating commercialization.

The length of the appropriate demonstration period will vary considerably by technology. However, adequate demonstration periods (perhaps many years for larger scale technologies) are crucial to promoting investor confidence. **Moreover, the nature of the demonstration program —i.e., who is participating, who is responsible for managing it, and the applicability of the program to a wide variety of utility circumstances —is of equal importance. Among the most successful demonstration ventures have been and are likely to continue to be cooperative ventures between industry (manufacturers and either utilities or nonutility power producers) and the Federal Government, with significant capital investments from all participants in the venture.** The current AFBC, IGCC, and geothermal demonstrations are good examples. In particular, **for larger scale technologies in utility applications, cooperative industry-government demonstration efforts, managed by the utilities, have a good track record.** For accelerated deployment, similar projects would be required for fuel cells, CAES, advanced battery technologies, and central receiver solar thermal powerplants.

The relationship between utilities and public utility commissions in early commercial applications of new generating and load management technologies is an important factor that will affect the deployment of these technologies in the 1990s. In particular, increased research, development, and demonstration activity will require utilities and utility commissions to agree on appropriate mechanisms for supporting such activities. Direct support alone from the rate base for research activities (e.g., as the allowance for contributions to the Electric Power Research Institute) may be desirable and important, but they are not sufficient to assure extensive deployment of these technologies by the 1990s. **Much larger commitments that involve large capital investments such as major demonstration facilities may only be justified by a sharing of the risk between ratepayers, stockholders and, if other utilities would benefit substantially, taxpayers.** One mechanism for supporting such projects is to finance a portion of a proposed project with an equity contribution from the utility and the rest through a "ratepayer loan" granted by the public utility commission. The public utility commission might argue that a candidate demonstration project is too risky for the ratepayer to be subsidizing it, particularly if other utilities could benefit substantially from the outcome if successful and are not contributing to the demonstration, i.e., sharing in the risk. In such cases, there could be a Federal role; for example, the ratepayer contribution to the demonstration could be underwritten by a Federal loan guarantee.

Other Policy Actions

In addition to maintaining a continued presence in research, development, and demonstration and implementing environmental policy affecting power generation, **several other Federal policy decisions affecting electric utilities could influence the rate of commercial development of new generating technologies over the next several years. These include removal of the Powerplant and Industrial Fuel Use Act (PIFUA) restrictions on the use of natural gas, and making PURPA Section 210 benefits available to electric utilities**. These steps could increase the rate of deployment of developing generating technologies, but their other effects will have to be carefully reviewed before and during implementation.

A more liberal power generation exemptions policy under PIFUA or an outright repeal of the Act could, in addition to providing more short-term fuel flexibility for many utilities, be an important step toward accelerated deployment of "clean coal" technologies such as the IGCC which can use natural gas as an interim fuel. Some new technologies such as CAES and several solar thermal technologies use natural gas as an auxiliary fuel and would require exemption from PIFUA.

Permitting utilities to participate more fully in the PURPA Section 210 benefits of receiving avoided cost in small power production is likely to result in increased deployment of small modular power generating technologies, particularly cogeneration. For example, utilities are currently limited to less than 50 percent participation in PURPA qualifying cogeneration facilities. In addition, with full utility participation in PURPA, ratepayers likely would share more directly in any cost savings resulting from these kinds of generating technologies. Allowance of full PURPA benefits for utilities, however, could cause avoided costs to be set by the cost of power from the cogeneration unit or alternative generation technology. Such avoided costs would likely be lower than if they were determined by conventional generating technologies as now is the case. Lower avoided costs would reduce the number of cogeneration and alternative technology power projects started by nonutility investors. Expanded utility involvement, though, may more than compensate for this decrease.

In relaxing the PURPA limitation potential problems require attention, including ensuring that utilities do not show preference for utility-initiated projects in such areas as access to transmission or capacity payments. Moreover, project accounting for PURPA-qualifying projects would probably need to be segregated from utility operations and non-PURPA qualifying projects in order to prevent cross-subsidization which would make utility-initiated projects appear more profitable at the ratepayers' expense. These concerns can be allayed through carefully drafted legislation or regulations, or through careful State review of utility ownership schemes.

Finally, as perhaps a logical next step to PURPA, a number of proposals for deregulation of the electric power business have been proposed in recent years, ranging from deregulation of bulk power transfers among utilities, to deregulation of generation, to complete deregulation of the industry. While OTA has not examined the implications of alternative deregulation proposals, such proposals, if enacted, would almost certainly have an impact on new generation technologies. The experiences of PURPA and the Southwest Bulk Power Transaction Deregulation Experiment will be important barometers for assessing the future prospects and desirability of deregulating U.S. electric power generation. It is important to note that allowance of full PURPA benefits for utilities would be a significant step toward deregulation of electric power generation, at least for smaller generating units.

Renewable Energy Tax Credits

Along with direct support for research and development and joint venture demonstration projects, an important component of the Federal program for new generating technology commercialization has been favorable tax treatment through such mechanisms as the Renewable Energy Tax Credits (RTCs), the Investment Tax Credit (ITC), and ACRS depreciation allowances. **The RTC, in particular, coupled with recovery of full utility avoided costs (under PURPA) by nonutility power producers have been crucial in the initial commercial development and deployment of wind and solar power generating technologies. With declining direct Federal support for renewable technology development, the RTC has supported development of advanced and innovative designs as well as commercial deployment of mature designs. Without continued favorable tax treatment, deployment of solar, wind and geothermal technologies is likely to be slowed significantly—certainly in nonutility applications.** Without existing tax incentives, many of the mostly small firms involved in development projects will lose access to existing sources of capital. Even large, adequately capitalized firms may lose their distribution networks, making industry growth more difficult.

With favorable tax treatment, some new technologies, such as geothermal and wind, have become important sources of new and replacement generating capacity in the West and Southwest. However, they must compete with more mature, modular technologies, e.g., conventional cogeneration technologies. And these modular technologies will continue to account for an important share of the new generating capacity, in the form of both utility and nonutility owned (and perhaps joint) ventures.

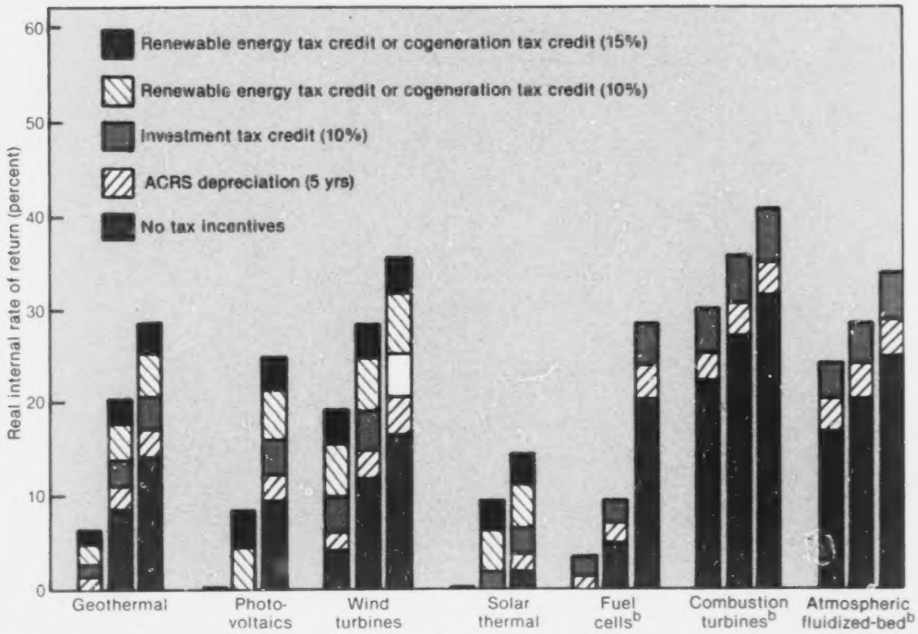
Figure 2-1 shows the cumulative effect of tax benefits, including accelerated depreciation allowances (ACRS), ITCs, and RTCs on the real internal rate of return for technologies considered in this assessment under the condition of nonutility ownership. (IGCC is not included in this figure since it is unlikely to be developed in nonutility power projects.) **The figure shows that the RTC may be crucial to the commercial survival of the renewable technologies with the possible exception of wind which may be mature enough to survive without these credits. The number of firms involved in wind technology development, however, would probably decrease markedly without these credits.**

The role of the RTC in accelerating commercial development seems to have changed. The original Federal policy was to provide direct research support to develop the technology and the RTC to accelerate commercial deployment. **With decreased Federal research and development support, the RTC appears to be supporting research and development in the field; this might partially explain the wide variation in performance of wind projects in recent years.**

A frequently proposed alternative to the RTC, in order to ensure performance of projects claiming a credit, is a Production Tax Credit (PTC) which provides benefits only with electricity production. OTA analysis of the PTC shows that geothermal and wind technologies benefit most from a PTC. **Others such as CAES and the direct solar technologies are aided only by a very large PTC. Similarly, tax benefits tied to production discourages producers from testing innovative designs since, if the design does not perform as expected, no benefits will be realized.** Another potential problem with the PTC is that monitoring electricity production may be difficult, particularly in applications that are not grid connected.

Other actions cited earlier for stimulating development in new technology within electric utilities may be more effective than tax preferences. For example, the decrease in the levelized per kilowatt-hour busbar cost for the renewable technologies considered in this assessment, with a 15 percent tax credit over and above the existing tax benefits currently afforded to utilities, is less than 10 percent for all cases.

Figure 2-1.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return[a]



[a] Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.

[b] In cogeneration applications.

SOURCE: Office of Technology Assessment, U.S. Congress.

Chapter 3

Electric Utilities in the 1990s: Planning for an Uncertain Future

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Chapter 3

Electric Utilities in the 1990s: Planning for an Uncertain Future

INTRODUCTION

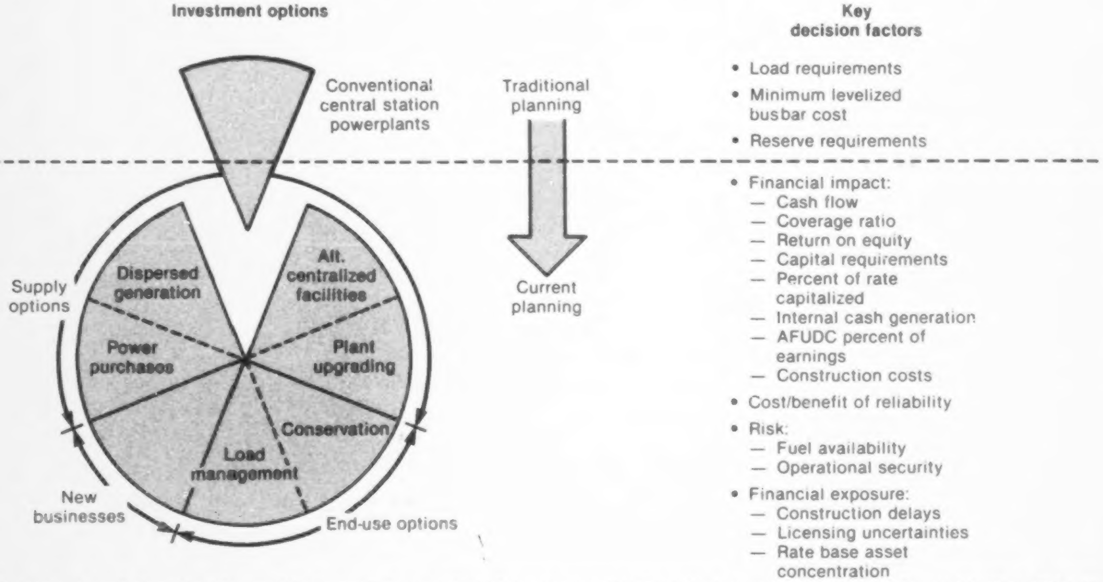
Overview

In the early 1970s, the U.S. electric power industry entered a new era. Long a stable force in the U.S. economy, the industry as a whole emerged in the 1980s under considerable financial stress and uncertainty, precipitated by skyrocketing fuel prices, escalating capital and construction costs, and a declining and erratic demand growth.

Even as utilities recovered from the shocks of the 1970s, it was clear that they would not return to business as usual, circa 1960s. The highly uncertain decision environment has forced utilities to reexamine their traditional business strategies as they look to the 1990s and beyond. Indeed, the basic procedures traditionally used by utilities in making future investment decisions have, in many cases, been drastically changed by the utilities themselves as well as by security analysts, investors, regulators, and ratepayers.

In this chapter we examine the strategic options being considered by utilities over the next two decades and, in particular, focus on the circumstances under which investment in new generating technologies might play a significant role for electric utilities through this period, compared with other strategic options. These other options include continued reliance on conventional supply sources, life extension and repowering of existing plants, increased purchases of power from neighboring utilities, or diversification to other nonutility lines of business (see figure 3-1). In addition, we review the arguments for and against the use of alternative technologies under different planning scenarios.

Figure 3-1.—Utility Investment Alternatives


Investment options
Conventional central station powerplants
Traditional planning
Current planning
Dispersed generation
Alt. centralized facilities
Power purchases
Plant upgrading
Conservation
Load management
Supply options
New businesses
End-use options
Key decision factors
• Load requirements
• Minimum levelized busbar cost
• Reserve requirements
• Financial impact:
— Cash flow
— Coverage ratio
— Return on equity
— Capital requirements
— Percent of rate capitalized
— Internal cash generation
— AFUDC percent of earnings
— Construction costs
• Cost/benefit of reliability
• Risk:
— Fuel availability
— Operational security
• Financial exposure:
— Construction delays
— Licensing uncertainties
— Rate base asset concentration

SOURCE: Adapted from D. Geraghty, "Coping With Changing Risks in Utility Capital Investments," unpublished paper, Electric Power Research Institute, February 1984.

The extent to which new generating technologies might play a role in electric utilities in the 1990s depends on how favorably such technologies compare with capital investments in conventional generation alternatives. It also depends on the managerial skills and financial resources of individual utilities. The role of nonutility producers of electricity is discussed later.

A number of 1982 surveys[1] suggested that utilities are not very interested in investing in new generating technologies. A variety of contingencies—such as persistent cost-control problems with large, central-station coal or nuclear plants now under construction or increased environmental control requirements, e.g., to reduce acid rain—however, are beginning to make such investments look much more appealing to utilities in the 1990s.

Currently, much of the investment in new electric generating technologies in the United States is not being undertaken by utilities at all, but by nonutility owners generating power under the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) (see box 3A). To date, much of this investment has gone into cogeneration. In some utility service areas, e.g., in California, the rate of growth of new generating technologies is steadily increasing (see figure 3-2).[2] Hence, the degree to which nonutility investment in new generating technologies (and load management) affects the total generation mix is also an important ingredient in the future of the U.S. electric power system.

The ultimate penetration of new technologies over the next two decades in many regions may well hinge on the relationship which evolves between utilities and nonutility owners. It will depend on the stringency of the utilities' interconnection requirements and on the rates the nonutility electricity producers receive for their electricity from the utilities. At present, these requirements and rates vary greatly across the United States (see chapter 7).

Box 3A.—The Public Utility Regulatory Policies Act of 1978

The Public Utility Regulatory Policies Act (PURPA), enacted in 1978, required the Federal Energy Regulatory Commission (FERC) to promulgate rules (under Section 210 of the Act) mandating purchase of electricity from qualifying small power producers (qualifying facilities—QFs) at rates "just and reasonable" to consumers, nondiscriminatory against producers, and not in excess of the incremental cost to the electric utility of electricity from other sources, i.e., if the purchasing utility generated the power itself. In its final rules implementing Section 210, FERC left the establishment of "avoided cost" rates up to the States to determine but also permitted States to set such rates higher than full avoided costs should it be found in the public interest to encourage cogeneration and small power production. Most States have issued implementing orders or at least interim rules for this PURPA requirement but the methods used have been quite varied (see chapter 7).

In establishing avoided cost rates, a principal area of variation among the States has been in evaluating QFs to receive *capacity payments*, granted as part of a QF's negotiated avoided cost rate when firm peak capacity is provided to the utility, allowing the purchasing utility to cancel or defer construction of new generating facilities. Less of an issue, although still varying widely among the States, is the establishment of *energy credits*, i.e., the value of the fuel or purchased power displaced by the QF.

Even though PURPA has been in effect for over 5 years, its implications are only beginning to be realized in many areas of the country. In some areas, such as California and the Southwest where avoided cost rates are high due to high fuel costs of existing generation, the contribution to total installed capacity by QFs is likely to be quite significant over the next two decades. This likelihood adds yet another dimension to the complicated investment planning problems facing utilities; these complications are discussed later in this chapter and in chapter 6.

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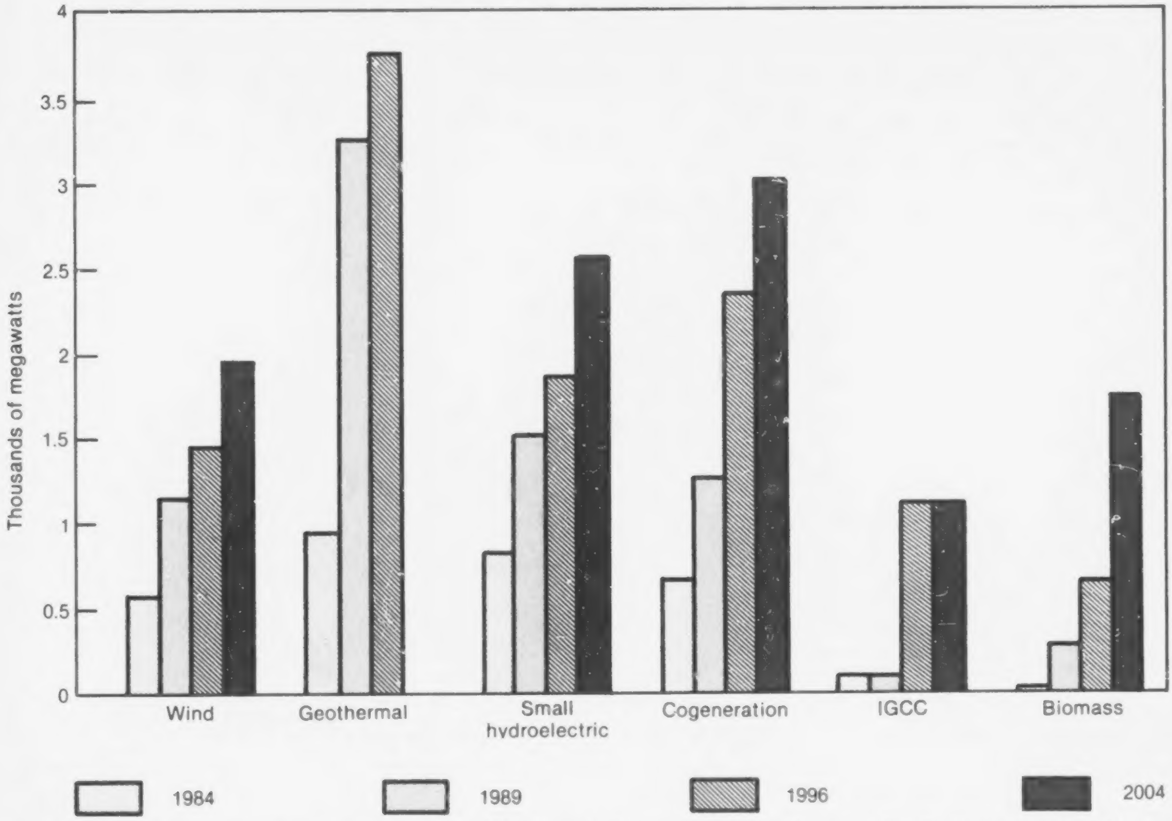
[1] "Plans and Perspectives: The Industry's View," *EPRI Journal*, October 1983; Douglas Cogan and Susan Williams, *Generating Energy Alternatives: Conservation, Load Management, and Renewable Energy at America's Electric Utilities* (Washington, DC: Investor Responsibility Research Center, Inc., 1983); *A Review of Energy Supply Decision Issues in the U.S. Electric Utility Industry* (Washington, DC: Theodore Barry & Associates, September 1982).

[2] This rate of growth has been so fast in California that the State declared a temporary moratorium on cogeneration projects in late 1984; the figure shows both utility and nonutility involvement in alternative technology projects.

Figure 3-2.—Alternative Power Generation in California (utility and nonutility owned capacity)



Projections were also made for photovoltaics—11 MW by 2004. All projections were made based on currently offered standard offers from California utilities; the total 1989 projected levels of penetration of cogeneration wind, small hydroelectric, photovoltaics, and energy from biomass total 6,290 MW.

SOURCE: Californnia Energy Commission, "Resource Estimates of Small Power Technologies in California," unpublished, 1984.

Historical Context

Overview

The basic framework for planning, forecasting, and analysis used today by the electric power industry in the United States is primarily the result of an industry-government relationship that has evolved since the earliest days of the industry.[3] The Federal Power Act of 1935 standardized the operating characteristics in the industry. Perhaps the most important feature of this legislation was not so much its guidelines for standardization, but more its general mandate for the industry:

> Provide an abundant supply of electric power with the greatest possible economy and with regard to proper utilization and conservation of natural resources.

In practice, this mandate was interpreted as requiring the provision of power at any time of day and in any quantity demanded.[4] As a result, the primary objective of electric utility operations in the United States is to meet the collective demand presented by all of its customers. The Federal Power Act required that this demand be met in an economically efficient manner both in dispatching generators to meet the daily load as well as in developing plans for new construction.

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[3] In these early days power systems of two basic designs were evolving simultaneously, namely the DC power system advocated initially by Thomas Edison and the AC network initiated by George Westinghouse. Indeed, in these early days some major cities maintained two independent parallel distribution systems, sometimes even strung on the same utility poles. The AC system eventually prevailed, of course, largely due to the use of transformers which permitted stepping up transmission voltages for higher efficiency and stepping down distribution voltages for safer and easier use; see P. Sporn, *Vistas in Electric Power* (New York: McGraw Hill, 1968).

[4] This mandate is not the rule in many foreign countries which has led to quite a different history of electric power production in these countries.

Until the late 1960s, electric utilities had been able to reliably and economically plan additions to their installed generating capacity to meet future demand while retiring aging plants. Until that time, demand growth forecasts had been reasonably accurate, powerplant construction lead times had been reasonably predictable, and construction as well as fuel cost changes had been small. Construction costs (per kilowatt installed) in fact decline as powerplants are scaled up in size. Electric utilities were viewed as sound investment opportunities by the capital markets. Thus, capital was available at relatively low cost.

Since the late 1960s, however, several factors have combined to create problems for the electric utilities. Both their financial performance and ability to make system planning decisions using the planning tools of the past have deteriorated as a result. Among these factors (discussed in more detail in the next section) are: 1) the growing difficulty of making demand forecasts—the industry as well as nearly all interested parties consistently underestimated the potential for conservation, i.e., the price elasticity of demand; 2) the dramatic increase in environmental protection costs resulting from the public's growing concern over the environmental effects of electric power production, especially air pollution from coal; 3) the unprecedented and escalating cost of new powerplants, especially nuclear powerplant construction due to unexpected delays, inflated capital costs, stricter safety standards (especially after Three Mile Island), unpredictable regulation, and uneven project management; and 4) high as well as uncertain fuel prices and supplies. The legacy of this traumatic period has been an industry in which both investors and utility managers are acutely aware of the industry's financial fragility and uncertain demand outlook and are therefore more cautious about committing their capital to large new coal and nuclear plants.

The prognosis for the power industry is uncertain. While it is possible that demand growth rates may increase once again over the next decade, it is also possible that changing industry fuel choices, saturation of electricity use in buildings, and improved efficiency of electricity use in all sectors of the economy as well as other conservation measures may moderate demand growth to less than 2 percent per year. Most current estimates range from 1.5 to 5 percent per year (see figure 3-3). The issue of uncertainty in demand growth is discussed in more detail in a previous OTA assessment.[5]

In the following, the impact these interrelated financial, regulatory (including environmental), and cost escalation stresses have had on the decisionmaking environment in the electricity industry are sketched in more detail.

Increasing Fuel Prices and Supply Uncertainty

Figure 3-4 shows the national average fossil fuel prices paid by electric utilities in the United States over the last decade; weighted average fossil fuel prices more than tripled between 1970 and 1980. Those utilities relying on significant levels of oil and natural gas (principally the East and Southwest—see figures 3-5 and 3-6) are shifting their generation mix to more capital-intensive nuclear and coal generation due to the uncertain future costs and supply of oil and natural gas. The recent stabilizing of oil and natural gas prices and excess supply of natural gas has only added to the uncertainty about future supply and prices.[6] (The regional variations in generation mix, fuels and other factors are discussed in chapter 7.)

Increasing Powerplant Construction Costs

Increased attention to environment and safety issues over the last decade has contributed to both extended lead times in the siting, permit-

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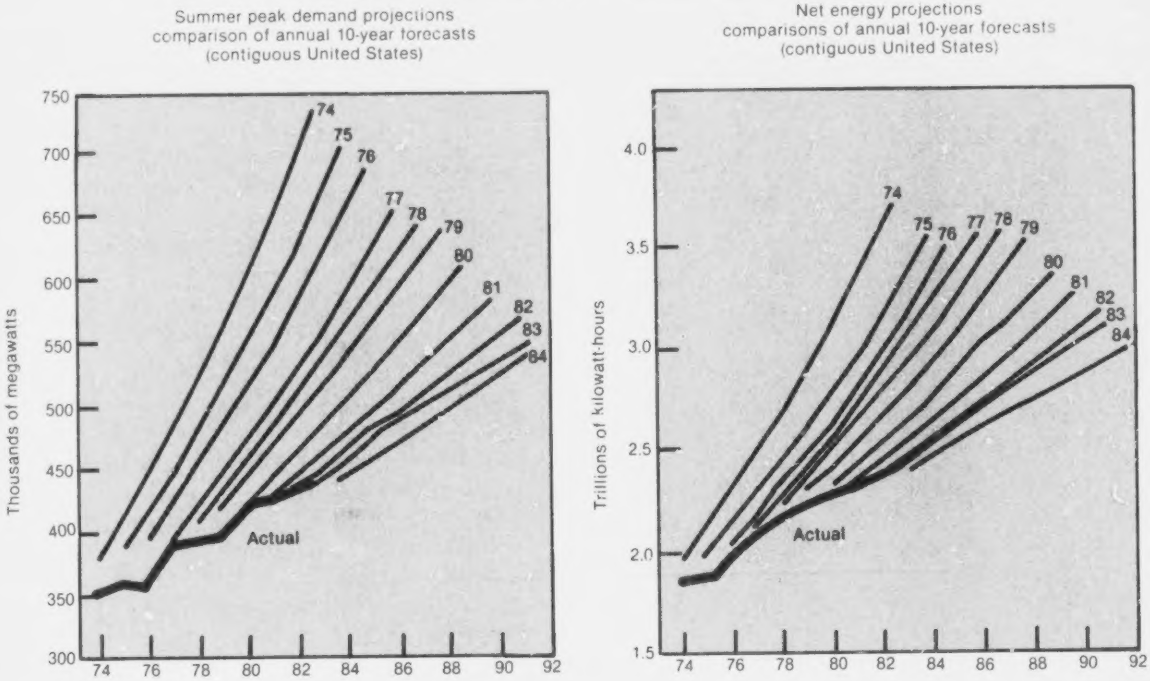
[5] U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216, ch. 3.

[6] See U.S. Congress, Office of Technology Assessment, *U.S. Natural Gas Availability: Gas Supply Through the Year 2000* (Washington, DC: U.S. Government Printing Office, February 1985), OTA-E-245.

Figure 3-3.—Projections of U.S. Electric Load Growth



Summer peak demand projections
comparison of annual 10-year forecasts
(contiguous United States)

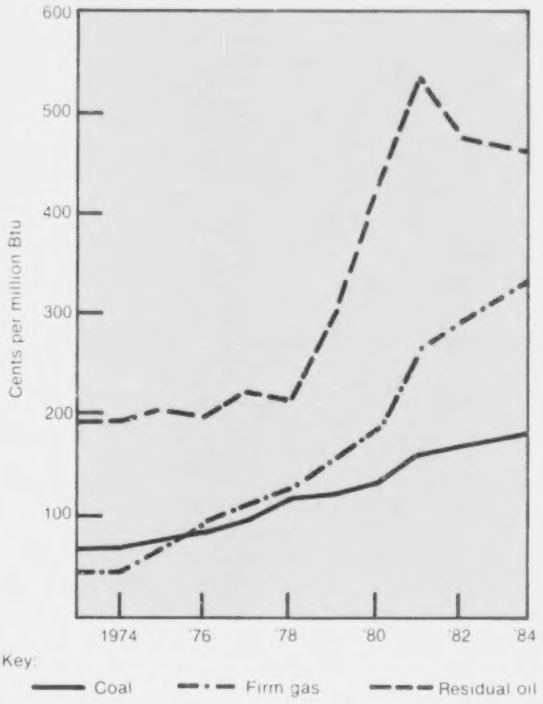
Net energy projections
comparisons of annual 10-year forecasts
(contiguous United States)

Average annual growth rate (%) projecting 10-years	Average annual growth rate (%) projecting 10-years
1974 - 7.6	1974 - 7.5
1975 - 6.9	1975 - 6.7
1976 - 6.4	1976 - 6.3
1977 - 5.7	1977 - 5.8
1978 - 5.2	1978 - 5.3
1979 - 4.7	1979 - 4.8
1980 - 4.0	1980 - 4.1
1981 - 3.4	1981 - 3.7
1982 - 3.0	1982 - 3.3
1983 - 2.8	1983 - 3.2
1984 - 2.5	1984 - 2.6

Other projections (1985-95)	
EPRI	2.00%
Electricity Policy Project	2.65%
Electrical World	2.85%
EIA	3.25%
Spangler and Wright	4.00%
Siegel and Sillen	5.00%

SOURCES: Summer peak, net energy, and average annual 10-year growth rate forecasts are from North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984). Other projections (1985-95) are drawn from: Electric Power Research Institute (EPRI), "U.S. Energy for the Rest of the Century," Workshop Proceedings, Oct. 25-26, 1983, Palo Alto, CA; U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Annual Energy Outlook 1984* (Washington, DC: U.S. Government Printing Office, January, 1985), DOE/EIA-0383(84); "35th Annual Electric Utility Industry Forecast," *Electrical World*, vol. 198, No. 9, September 1984, pp. 49-56; U.S. Department of Energy (DOE), Report of the Electricity Policy Project, *The Future of Electric Power in America: Economic Supply for Economic Growth* (Washington, DC: National Technical Information Service, June 1983), DOE/PE-0045; John Siegel and John Sillin, "The Coming Power Boom: An Assessment of Electric Load Growth in the 1980's," testimony presented to the Nuclear Regulatory Commission, November 1984; and Gordon L. Spangler and Vincent P. Wright, "Another Look At growth In Demand for Electricity," *Public Utilities Fortnightly*, vol. 113, No. 9, Apr. 26, 1984, pp. 25-28.

Figure 3-4.—National Average Fossil Fuel Prices Paid by Electric Utilities[a]



[a]Prices are expressed in nominal dollars

SOURCE: Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses—1980* (Washington, DC: U.S. Government Printing Office, June 1983), DOE/EIA-0323(80).

ting, and construction process of new powerplants as well as to rapidly rising per kilowatt costs of these plants, particularly coal and nuclear plants as shown in figure 3-7.

Increased Financing Costs

Since the electric utility business is the most capital-intensive in the American economy (see figure 3-8), its financing costs are particularly sensitive to inflation. Inflation has become an important parameter in the cost of plant construction as a consequence the large size and long leadtimes of new coal and nuclear plants.

Long-term debt, available at around 6 percent in the 1960s, more than doubled in cost by 1980.[7] Equity capital for investor-owned utilities also became more costly; with earnings falling relative to cost, a utility must issue stock to maintain prescribed debt-equity ratios in order to continue borrowing. With lower earnings, however, new stock issues have diluted the value of existing shares to the point where, in 1983, almost half of the hundred largest utility stocks traded at below book value. This situation has improved substantially since early 1983 (see figure 3-9) and in early 1985 many utility stocks are once again trading above book value.[8]

Decreased Demand Growth

With dramatically increased costs in the electric utility business over the last decade, particularly in financing and fuel, in the mid-1970s many utilities for the first time in many years sought higher rates. Utility commissions generally granted relief (see table 3-1), however, the response of consumers was swift but unprecedented.[9] Demand growth dropped dramatically in the 1970s to less that 2 percent (see figure 3-10), although there were wide variations in this trend throughout the United States (see chapter 7). The price elasticity of demand was underestimated by many utilities and these utilities were often unwilling or unable to revise their construction plans made in the late 1960s and early 1970s. The result was decreased net revenues and excess generating capacity for most utilities, further eroding their financial performance (the reserve margin for electric utilities rose from about 20 percent in the early 1970s to over 30 percent in late 1970s, and to 35 percent in 1984).

Effect of Eroded Financial Performance

The decrease in electric utility earnings per share relative to other industries in the 1970s was

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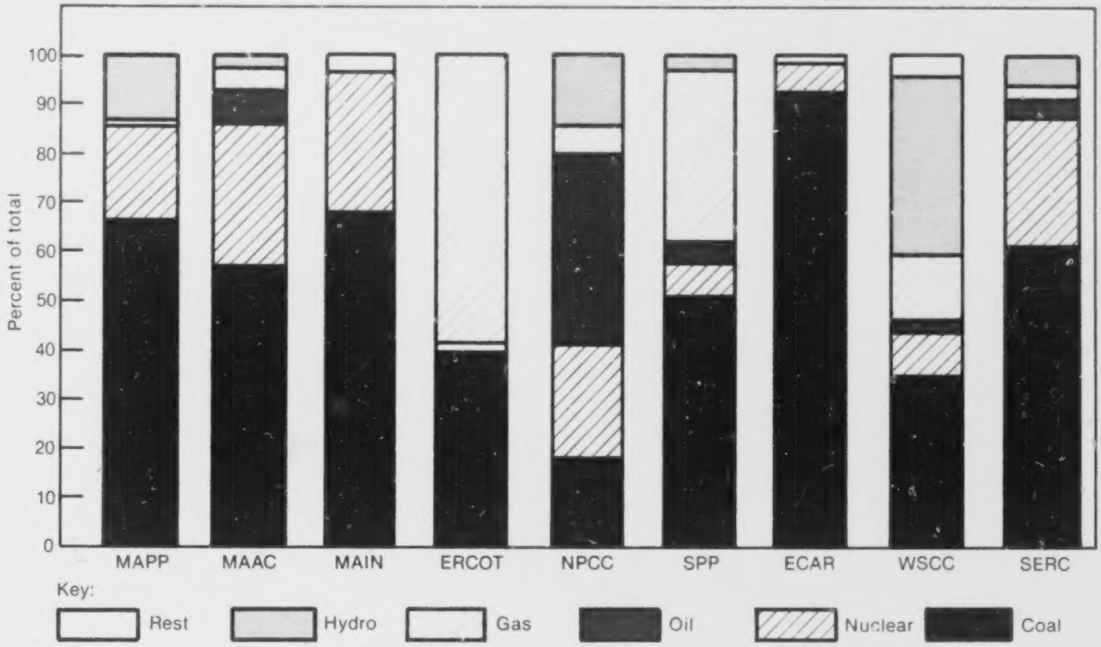
[7] An investor-owned electric utility today requires about $2.86 of investment per dollar of annual revenue compared with a dollar or less of investment per dollar of revenue for manufacturing industries; the electric utility industry (investor-owned) in the United States accounts for one-tenth of all new industrial construction in the country, a third of all corporate financing, and almost half of all new common stock issuances among industrial corporations; see S. Fenn, *America's Electric Utilities: Under Siege and in Transition* (New York: Praeger Publishers, 1984).

[8] The market-to-book ratio (used in figure 3-9) can, however, sometimes be a misleading indicator; see M. Foley, "Electric Utility Financing: Let's Ease Off the Panic Button," *Public Utilities Fortnightly*, vol. 111, No. 1, Jan. 6, 1983, pp. 21-29.

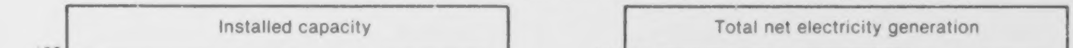
[9] Even though the real costs of electricity compared to oil and gas, for example, did not increase substantially, the changes in demand growth were just as dramatic.

Figure 3-5.—Regional Net Generation of Electricity by Fuel Type, 1984



SOURCE: Office of Technology Assessment, using data from North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

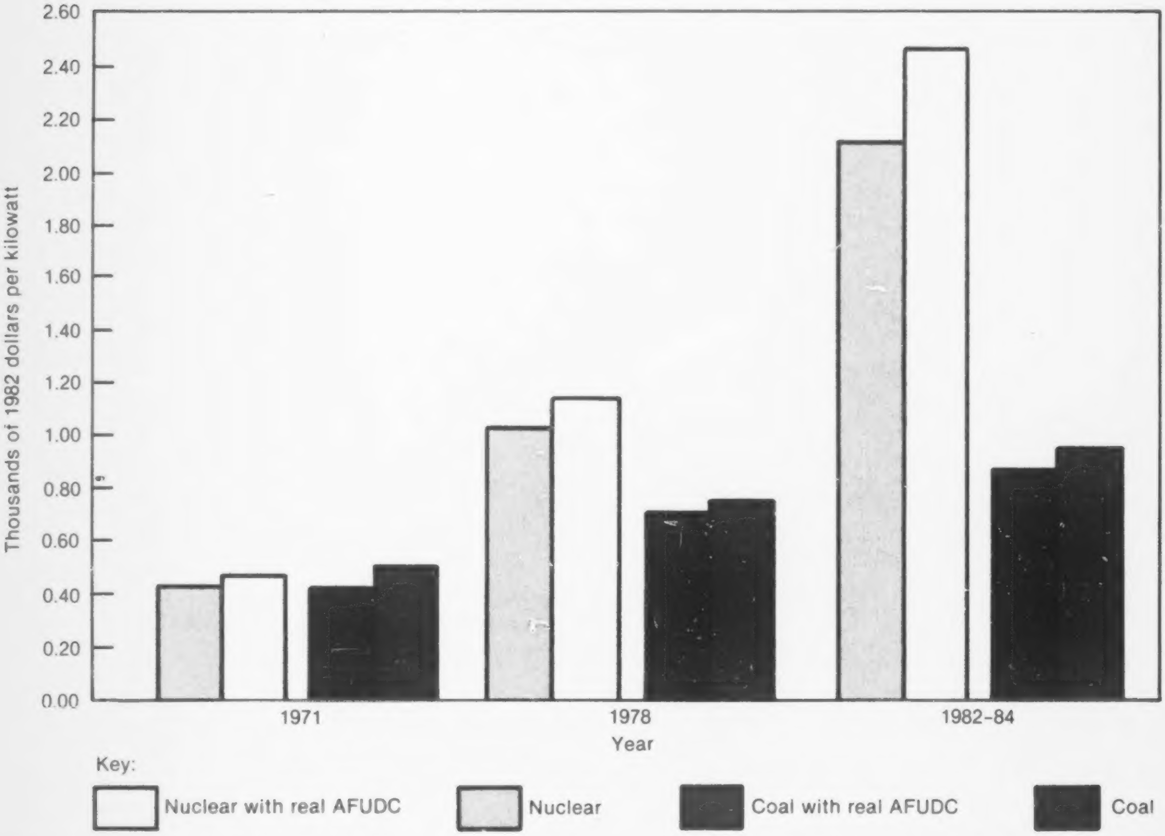
Figure 3-6.—U.S. Generation Mix by Installed Capacity and Electricity Generation



[a] Includes dual-fuel generation as defined by NERC.

SOURCE: Office of Technology Assessment, from data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1983-1992* (Princeton, NJ: NERC, 1983); and NERC, *Electric Power Supply and Demand, 1984-1993 (Princeton, NJ: NERC, 1984).*

Figure 3-7.—Electric Powerplant Cost Escalation, 1971-84



SOURCE: Charles Komanoff, *Power Plant Cost Escalation* (New York: Komanoff Energy Associates, 1981); and Charles Komanoff, "Assessing the High Costs of New Nuclear Power Plants," *Public Utilities Fortnightly*, vol. 114, No. 8, Oct. 11, 1984; construction costs do not include real AFUDC, i.e., they are based on actual construction times and real (net-of-inflation) interest rates.

a decrease in quality as well as quantity. In particular, since most utility commissions do not permit a return on any investment costs from a powerplant until it actually is in service, most utilities are permitted only to account for construction costs as an "Allowance for Funds Used During Construction"(AFUDC) and apply them to the rate base when the facility is placed in "used and useful" service. Hence, AFUDC earnings appear as part of a utility's stated earnings but, of course, they are not current revenues at all, only paper earnings. As a result, the higher the fraction of total earnings attributed to AFUDC, the lower the quality of those earnings. More recently, the practice of allowing some of the costs associated with "Construction Work in Progress" (CWIP) to be applied to the utility rate base prior to completion has been permitted by some utility commissions. The issue of allowing CWIP in the rate base is discussed in more detail in chapter 10. Today, over a half of the total earnings nationally by investor-owned utilities is AFUDC (see figures 3-11 and 3-12).

The general deterioration of financial performance of utilities has strained stockholder confidence. Indeed, in an effort to maintain this confidence many utilities have actually borrowed at short-term high interest rates to pay out dividends to shareholders.[10] Likewise, the consistently high

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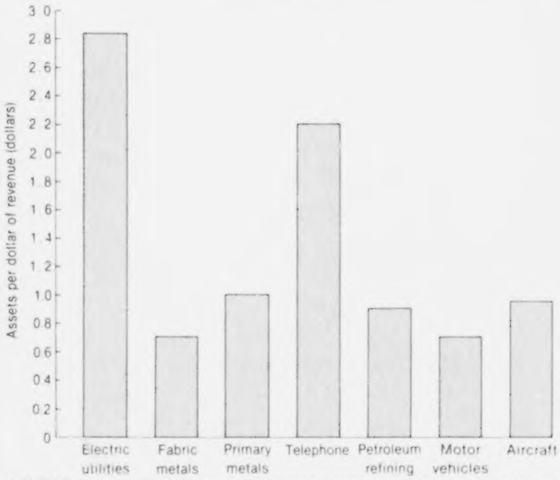
[10] Perhaps a milestone in recent utility history was Consolidated Edison's missed dividend payment in 1974 (see Foley, op. cit., 1983); more recently missed dividends by Public Service of New Hampshire, Consumers Power, and Long Island Lighting Co. are signaling concern to investors.

Figure 3-8.—Capital Intensity of Electric Utilities, 1982



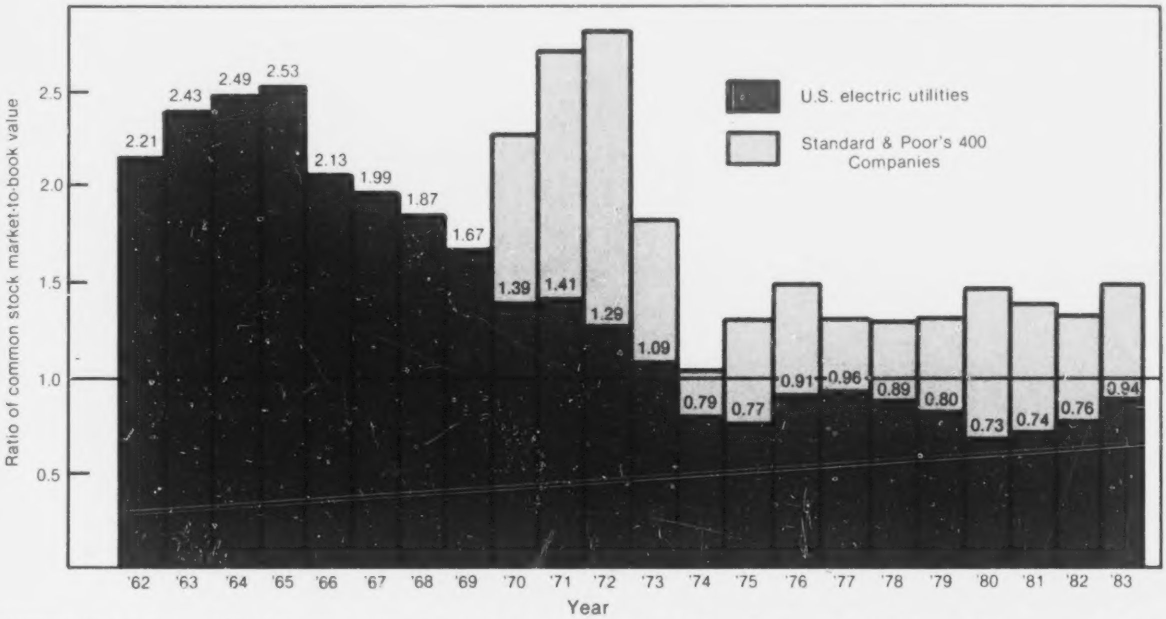
SOURCE: Bureau of the Census, U.S. Department of Commerce, "Quarterly Financial Report for Manufacturing, Mining and Trade Corporations," 4th quarter, 1982.

average utility bond ratings (AAA or Aaa) in the 1950s and 1960s fell to an average of A and below in the 1970s and to in the 1980s (see figure 3-13). Again, these ratings have increased since 1983, but remain below the 1960s' levels. And, it did not go unnoticed by investors that the largest municipal bond default in American history occurred within the electric power industry in 1983, when the consortium of utilities known as the Washington Public Supply System defaulted on $2.25 billion of bonds on two nuclear powerplants. Many of the important financial indicators are summarized in table 3-2.

Financial Impacts of the Nuclear Experience

Beginning in 1983, the difference in financial performance between utilities involved in nuclear construction programs and those who are not has became particularly apparent. It is reflected, for example, in stock price—see figure 3-14. Since early 1983, the market-to-book ratio for the industry as a whole has risen substantially, but utilities involved in major nuclear projects have lagged behind. For nearly half of the industry currently involved in nuclear construction programs, the status of these projects and the economic reg-

Figure 3-9.—Electric Utility Market to Book Ratios, 1962-84



SOURCES: Marie R. Corio and Alice E. Condren, "Utilities-Electric: Basic Analysis," Standard & Poor's *Industry Surveys*, Mar. 1, 1984; and U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216.

Table 3-1.—Electric Utility Rate Applications and Approvals, 1970-84 (millions of dollars)

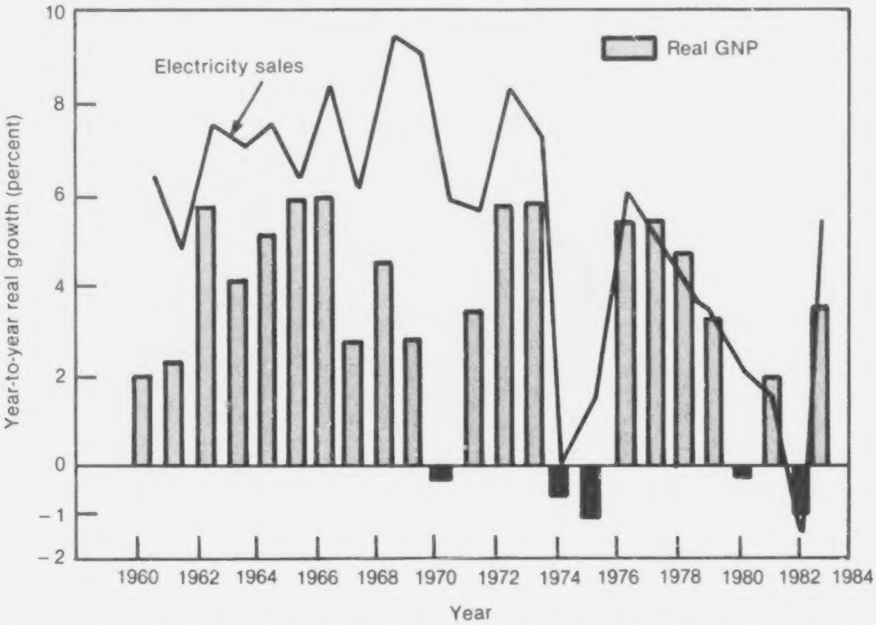
Year	Number of rate increases filed	Amounts requested	Amounts approved	Percent approved
1970	80	$ 797	$533	33.1
1971	113	$ 1,368	$826	39.6
1972	110	$ 1,205	$853	29.2
1973	139	$ 2,125	$1,089	48.8
1974	212	$ 4,555	$2,229	51.1
1975	191	$ 3,973	$3,094	22.1
1976	169	$ 3,747	$2,275	39.3
1977	162	$ 3,953	$2,311	41.5
1978	154	$ 4,494	$2,419	46.2
1979	178	$ 5,736	$2,853	50.3
1980	254	$10,871	$5,932	45.4
1981	237	$11,902	$8,341	29.9
1982	234[a]	$11,023	$7,629	30.8
1983	185	$12,783	$5,370	58.0
1984	61[b]	$ 4,900	$2,267	53.7

[a] Also includes two rate decreases.

[b] Through June 30, 1984.

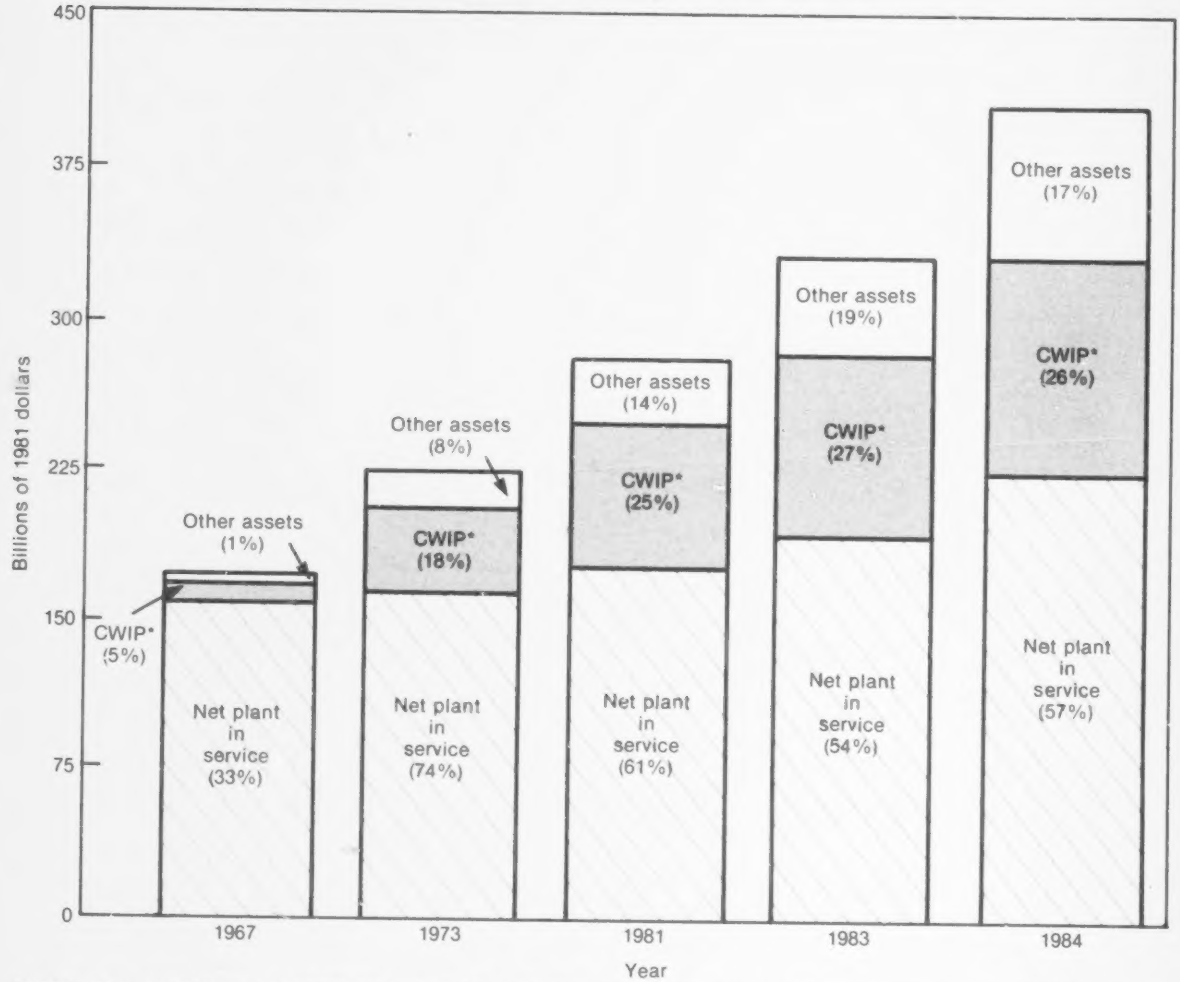
SOURCE: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

Figure 3-10.—Real GNP Growth and Electricity Sales Growth Rates, 1960-84



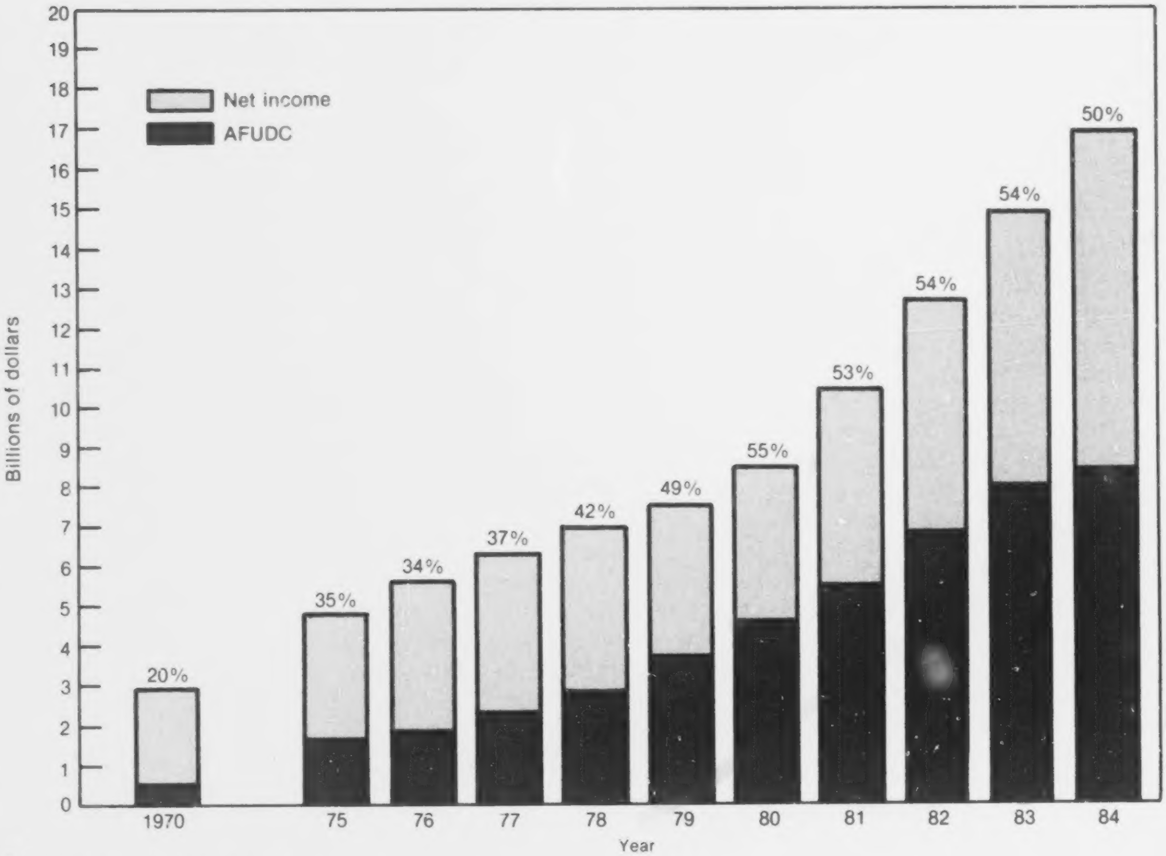
SOURCES: Craig R. Johnson, "Why Electric Power Growth Will Not Resume," *Public Utilities Fortnightly*, vol. 111, No. 8, Apr. 14, 1983, pp. 19-22; and Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

Figure 3-11.—CWIP As a Percentage of Total Investment



SOURCES: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984); and Energy Information Administration, *Statistics of Privately Owned Electric Utilities, 1981 Annual (Classes A and B Companies)* Washington, DC: U.S. Government Printing Office, June 1983), DOE/EIA-0044(81).

Figure 3-12.—AFUDC As a Percentage of Total Earnings[a]



[a] Net income available for common stock.

SOURCE: Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984).

ulatory response to cost overruns, plant abandonments, and excess capacity if the plants are completed, will weigh heavily on these utilities' financial performance over the next decade. Despite the fact that some utilities have demonstrated that the difficulties with nuclear technology are not insurmountable,[11] OTA concluded last year that:

> Without significant changes in the technology, management, and the level of public acceptance, nuclear power in the United States is unlikely to be expanded in this century beyond the reactors already under construction.[12]

Moreover, if utility commissions consider generating reserve margins excessive, they may not include all or part of expenditures in the rate base for some plants currently under construction.

The consequences of economic regulatory treatment of such plants could range from utility bankruptcies to large rate increases, often referred to as "rate shock" for customers. Such decisions will bring the issue of the ratepayers' versus stockholders' interests into sharp focus over the next decade; indeed many alternative proposals

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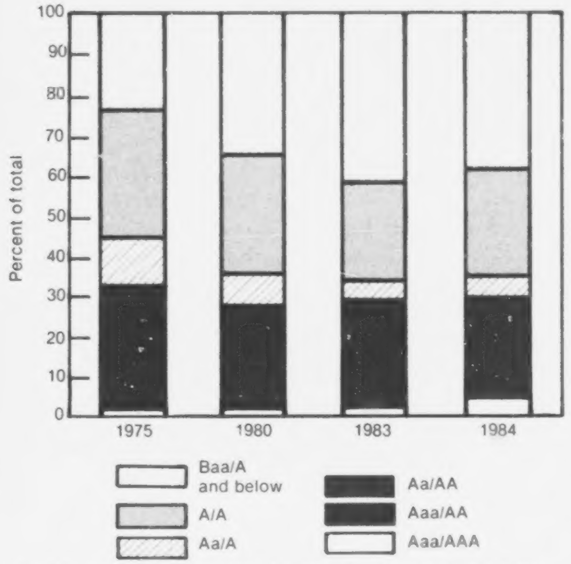
[11] The 85 nuclear plants operating in the United States today generally have an economical and reliable operating history; this is reinforced by the 227 nuclear plants now operating in foreign countries (a total of 531 plants are now operating, on order or under construction worldwide); see E. Meyer, et al., "Financial Squeeze on Utilities: Who Really Pays," *Public Utilities Fortnightly*, vol. 114, No. 12, Dec. 6, 1984, pp. 31-35.

[12] OTA, *Nuclear Power in an Age of Uncertainty*, op. cit., 1984.

Figure 3-13.—Electric Utility Bond Ratings, 1975-84



SOURCE: Salomon Brothers, Inc., *Electric Utility Quality Measurements—Quarterly Review*, New York, Jan. 3, 1984, and *Electric Utility Monthly*, Mar. 1, 1985.

for bringing large plants into the utility rate base are currently under intense debate.[13] Such issues are discussed in more depth later.

And finally, management of nuclear powerplant construction projects in the utility industry has been very uneven. Problems have occurred in all phases of nuclear construction programs from project design through quality control and cost control.[14]

Summary

The current state of affairs in the electric utility industry is one of considerable uncertainty over future demand growth, powerplant costs, and cost of capital. As a result, few utilities are willing to increase their investment risk and many have canceled or at least deferred large-scale, long lead-time construction programs. And interest by the industry in alternatives to the traditional strategy of building conventional large-scale generation plants is growing. In particular, these alternatives include intensified load management and conservation (either through direct load control or indirectly through the rate structure); rehabilitation of existing generating plant; and increased interconnection with neighboring utilities. Another alternative being considered is construction of smaller, and possibly decentralized, generation facilities that permit more flexible tracking of demand growth and reduced exposure to inflation and capital market fluctuations; more-

Table 3-2.—Financial Condition of Electric Utilities, 1952-84

Characteristic	"Golden age" 1952-66	"Transition" 1966-73	"Hard times" 1973-75	"Recovery" 1980	"Present" 1984
Ratio of internally generated funds to capital expenditures	0.8	0.5	0.3	0.42	0.42
Interest coverage ratio (pretax)	>5.0	3.0	2.4	3.0	3.38
Interest rate (%)	<4.6	6.0	8.5	15.27	10.79
Inflation rate (%)	1.25	4.5	8.0	13.5	3.5
Common stock price (% of book value)	250	150	95	73	95
Construction activity initiated	Average	Heavy	Cutbacks	Increased cutbacks	Very little
Electric rates	Decreasing	Steadily increasing	Accelerating	Increasing	Still increasing
Average return on equity (%):					
Including AFUDC	13	12	11	11.4	13.9
Excluding AFUDC	12	9	7.2	7.4	7.35

SOURCES: Rand Corp., *Electric Utility Decision Making and the Nuclear Option* (Santa Monica, CA: Rand Corp., 1977); Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, December 1984); and Marie R. Corio and Alice E. Condren, "Utilities-Electric: Basic Analysis," Standard and Poor's *Industry Surveys*, Mar. 1, 1984.

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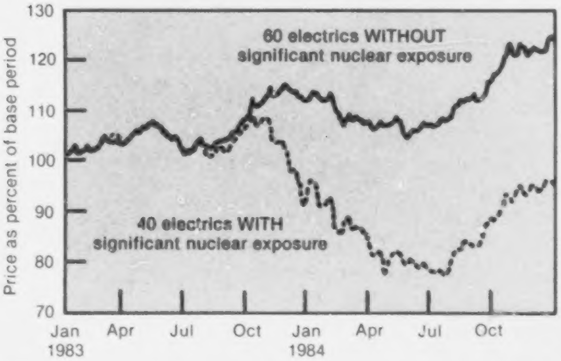
[13] See, for example, National Science Foundation, Division of Policy Research and Analysis, "Workshop on Alternative Electric Power Plant Financing and Cost Recovery Methods," Washington, DC, May 7, 1984.

[14] See, for example, James Cook, "Nuclear Follies," *Forbes*, vol. 135, No. 3, Feb. 11, 1985, pp. 82-100; and OTA, *Nuclear Power in an Age of Uncertainty*, op. cit., 1984.

Figure 3-14.—Stock-Price Performance of Nuclear and Nonnuclear Utilities



SOURCE: Salomon Brothers, Inc., "The Outlook for Electric Utilities in 1985," *Electric Utilities: Stock Research*, New York, Jan. 7, 1985, p. 4.

over, the smaller facilities enter the rate base more quickly. Also, utilities are increasingly interested in the potential contribution of new generating technologies which use both conventional and renewable energy resources. The question is how utilities will incorporate the characteristics of these new technologies into both their planning and operations, because they are generally quite different from those of conventional generating alternatives. In addition, nonutility owners are likely to play an increasingly crucial role in the application of these technologies.

The next section reviews the traditional decisionmaking process in the electric utility industry and the forces that are changing that process. Of particular importance to the industry over the next two decades will be the ability of any given utility's management to answer the following questions:

- Are the benefits of smaller scale, shorter lead-time plants—their lower financial risk, short-term financial sustainability, and greater flexibility in filling unpredicted demand—compelling enough to consider them more carefully as an alternative to conventional large-scale, long lead-time plants?
- If the benefits of smaller, shorter lead-time plants are considered sufficient along with other benefits such as increased efficiency or reduced emissions, what conventional small-scale alternatives and what unconventional new technologies will be considered? To what degree will use of conventional alternatives preclude significant use of new technologies?
- If unconventional new technologies are perceived as potentially important in a utility's future resource plan, what institutional changes might be necessary to accommodate these technologies? Will nonutility ownership be encouraged? How?

INVESTMENT DECISIONS BY ELECTRIC UTILITIES: OBJECTIVES AND TRADE-OFFS

Introduction

In the most general terms, the principal objectives of utility decisionmakers are to: 1) ensure that system reliability is maintained, 2) minimize their ratepayers' burden over time, and 3) maintain the financial health of their companies. Any decision analysis of investments must address these objectives. Of increasing importance, particularly in evaluating the potential for new technologies, is the degree of uncertainty affecting the company's future demand, cost of service, and performance. Accounting for this uncertainty is becoming a much more important component in the decisionmaking process of most utilities.

Investment Decision Objectives

Maintaining System Reliability

The first objective—maintaining system reliability—is often evaluated in terms of Loss of Load Probability (LOLP).[15] A prescribed level of LOLP is traditionally imposed on the utility's system planning function as a fixed constraint, e.g., one day in ten years the utility will be unable to meet its entire load. System planners then statistically analyze peak demand predictions, at full as well as partial outage estimates of their generation and major transmission facilities, in order to project reserve margins required to meet the LOLP constraint.

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[15] Other measures are reported in General Electric Co., *Reliability Indices for Power Systems*, final report prepared for Electric Power Research Institute (EPRI) (Palo Alto, CA: EPRI, March 1981), EL-1773, RP1353-1.

The critical uncertainties in this reliability analysis include: 1) the annual peak demand forecast, 2) scheduled and forced outage occurrences of needed generating units, 3) the power output of needed generating units, 4) the on-line dates of any new generating capacity that may be planned for the period in question, and 5) the availability of purchased power. Other factors such as load management or conservation efforts and dispersed sources of generation, e.g., cogeneration, add an additional element of uncertainty to the utility's reliability analysis. (See chapter 6.) This is because there is uncertainty regarding the extent to which conservation will moderate electricity demand and load management will alter demand patterns. Further, there is uncertainty about the market penetration that will be achieved by load management devices and by dispersed sources of generation. There is also uncertainty about their reliability.

In recent years, the traditional treatment of reliability as a fixed constraint--the prescribed LOLP level described earlier—is being called into question. In particular, the trade-off between total cost and quality of service is becoming an increasing concern.[16] The argument being advanced is that electricity should be treated more as a commodity in a segmented market (different customer classes), one aspect of which is quality of service which should be reflected in the commodity price. The current debate, therefore, centers around whether electricity should be available at a uniformly high level of reliability or at increasing degrees of reliability for increasing price levels.

Minimizing Electricity Rates

The second objective of utility decisionmakers is to minimize their electricity rates. They must show their efforts to achieve this objective in their applications for changes in rates to State public utility commissions. Generally accepted ratemaking practices are discussed in chapter 8 (box 8A). The objective of minimizing rates is often measured in terms of revenue requirements or the total cost per kilowatt-hour of electric energy generated. The principal cost elements to be considered when meeting this objective are:

1. fixed costs associated with the recovery of capital invested in generation, transmission and distribution facilities;
2. fixed and variable production costs associated with operation, maintenance and fuel expenses for supply facilities; and
3. overhead costs associated with general administrative expenses and working capital allowances.

In order to compare lifetime rate requirements of different generating technologies, utilities project, over the lifetime of each plant, each component of cost—return on capital, debt service cost, fuel and operating cost, and share of overhead—and then they apply a discount rate to each year's costs to calculate a levelized annual cost. Utility decisionmaking is complicated by the fact that plants with the same levelized cost can have very different year-to-year costs, and that utility rates are not set according to levelized cost but projected actual costs. During times of high inflation and high interest rates, the return on capital and the cost of capital-expensive plants is concentrated in the early years of a plant's life. For fuel-expensive plants the opposite is true—the year-to-year cost is initially low but increases over time. The implications of such trade-offs are discussed in more detail in chapter 8.

Maintaining Corporate Financial Health

The third objective of utility decisionmakers—to maintain the financial health of their companies—is typically assessed in terms of some key parameters such as growth in earnings, debt service coverage ratios, and return on common equity. System planning decisions which satisfy the two objectives discussed earlier (i.e., maintaining system reliability while minimizing ratepayers' burden) are also evaluated in terms of their impact, over time, on these measures of corporate financial health.

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[16] For example, see M. Telson, "The Economics of Reliability for Electric Generation Systems," *Bell Journal of Economics*, vol. 5, No. 2, autumn 1975, pp. 679-694.

Since the electric utility business is so capital-intensive, it relies heavily on its ability to raise capital from debt and equity sources. The availability and cost of this capital depends, to a large degree, on a utility's financial health as evaluated by security analysts and investment houses.

When evaluating a utility's financial health, these analysts weigh a wide range of qualitative and quantitative factors (see table 3-3). They seem, though, to emphasize five quantitative factors:

1. earnings protection—debt coverage,
2. leverage—equity share of total capitalization,
3. cash flow and earnings quality—share of AFUDC in total earnings,
4. asset concentration—shares of generating capacity compared to shares of the rate base, and
5. financial flexibility.[17]

In addition, they generally consider five qualitative factors:

1. prospects for demand growth in the service territory,
2. diversity of fuel supply,
3. quality of management,
4. operating efficiency, and
5. regulatory disposition.

Variations Among Utilities and Conflicting Objectives

Prior to the early 1970s, maintaining reliability was treated as a prescribed constraint and utilities generally had little trouble earning their allowed rate of return while achieving steady reductions in the cost of electricity, as discussed earlier. In other words, the three investment objectives could in effect be simultaneously pursued with little conflict, and the process just described generally explained utility investment decisions quite well, at least with respect to technology choice.

Table 3-3.—Elements Considered in the Utility Financial Rating Process

Economic analysis of service territory:
Population
Wealth
Employment
Size of service area and outlook
Historic and estimated load growth
Demand and energy sales

Type of system:
Self generation
Distribution
Combination
Wholesale and bulk power

Facilities:
Fuel mix, cost, availability, and price
Capacity and reserve
Operating cost
Operating ratio
Dispatching strategies

Capital improvement plans:
Realistic construction cost estimates
Alternatives to own construction

Rate structure:
Likely regulatory climate
Comparative rates
Ability to adjust

Bond security:
Revenues
Debt service reserve
Contingency fund
Capitalized interest
Rate covenant
Additional bonds covenant
Power contracts
Asset concentration

Key ratios:
Environmental concerns
Net take-down
Interest coverage
Debt service coverage
Debt service safety margin
Debt ratio
Interest safety margin
Percentage AFUDC
Percentage internal cost generation

Glossary for financial ratios:

1. *Operating ratio*: operating and maintenance expenses (excluding depreciation) divided by total operating revenues.
2. *Net take-down*: net revenues (gross revenues less operating and maintenance expenses) divided by system gross revenues.
3. *Interest coverage*: interest for year divided into net revenues available for debt service.
4. *Debt service coverage*: principal plus interest requirements for year divided into net revenues available for debt service.
5. *Debt service safety margin*: system gross revenues less operating and maintenance expenses and less current debt service divided by system gross revenues.
6. *Debt ratio*: net debt (gross debt as shown on balance sheet less bond principal reserve) divided by sum of net utility plant plus net working capital.
7. *Interest safety margin*: gross revenues less operating and maintenance expenses and less current interest for year divided by system gross revenues.

SOURCE: Standard & Poor's, "Standard & Poor's Bond Guide for 1983," 1983.

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[17] Thomas Mockler (Standard & Poor's), "Workshop on Investment Decisionmaking in Electric Utilities," sponsored by U.S. Congress, Office of Technology Assessment, Washington, DC, Apr. 17-18, 1984.

The actual implementation of a decisionmaking process varies across utilities, but there appears to be little difference among utilities in the generally accepted practices for making decisions. The differences, rather, are mostly in characterizing the alternatives to be considered. A recent survey of utility decisionmaking[18] reported that, in spite of the wide diversity of types of firms in the industry (see box 3B),

> . . . there is a high degree of uniformity in the plant investment decisionmaking practices followed by U.S. electric power firms, both public and private, as well as other regulated utilities.

In chapter 8 the analytical tools routinely used by utilities in making investment decisions are discussed. Also discussed are the differences among utilities, particularly with respect to differences in cost of capital (considerably different, for example, between public and private utilities), in discount rates, and in attitudes toward and methods for dealing with risk.

How utilities account for risk is important because it explains in part what might otherwise be a noneconomic choice in selecting a new technology. For example, uncertainty about demand growth, long-term financing conditions, or other "state of the world" factors may prompt more severe discounting for long-term risk against long lead-time projects. This has certainly been the case in recent years in the industry. Similarly, of particular relevance to this assessment, concern over a specific technology may swing a close investment decision one way or the other. The Edison Electric Institute[19] has classified the critical, supply-option, technology risks facing utility decisionmakers, these are summarized in table 3-4.

In addition, and reflected in some of these risks, factors relating specifically to regulatory approval are of increasing concern and have prompted utilities to carry out what is often termed "short-period analysis." In such an analysis, planners examine how specific areas of uncertainty, such as future environmental regulations or fuel availability, might affect the financial performance in the early years of a project's life.

This new, more complex investment decision environment of the 1980s has brought with it the possibility of conflicting objectives in making investment decisions. It has become possible that utilities could decide not to pursue the lowest projected lifetime cost option (minimizing rates) for future investments because of its implications for short-term financial performance (maintaining financial health). In the long run, maintaining financial integrity does indirectly affect the ratepayers' burden, but the relationship is less clear.

Perhaps to avoid such conflict, some utilities in recent years have made substantial changes in the way they make future investment decisions. For example, Pacific Gas & Electric's (PG&E) key corporate planning goals published in 1983[20] state an "adopted direction" including:

- operation within revenue and expense levels provided by rate case decisions,
- minimize capital expenditures, and
- avoid major commitments of capital to new energy supply projects.

For PG&E, this meant that "the company will not be committing capital to any major new electric supply projects, although minimal capital expenditures may result from efforts to keep options open." Variation in how a utility sets its basic direction for resource planning depends on regulatory pressure, financial position, and, perhaps most importantly, the character of utility management. Some utilities have substantially modified their "decisionmaking" mechanisms to better accommodate uncertainty and trade-offs in investment decisions, e.g., the "short-period" analysis described earlier.

The trade-offs among future investments are likely to be a fundamental issue of debate over the next decade, and this debate's outcome could profoundly affect the deployment of new technologies as they mature. Another recent industry survey, cited earlier[21] reports that, for the

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[18] G. Corey, "Plant Investment Decision-Making in the Electric Power Industry," *Discounting for Time and Risk in Energy Policy* (Washington, DC: Resources for the Future, 1982), pp. 377-403.

[19] Edison Electric Institute (EEI), *Strategic Implications of Alternative Generating Technologies* (Washington, DC: EEI, April 1984).

[20] Pacific Gas & Electric Co., *Long Term Planning Results: 1984-2004*, May 1984.

[21] Theodore Barry & Associates, op. cit., 1982.

Box 3B.—The U.S. Electric Utility Industry: A Profile

In 1984 the U.S. electric utility industry was made up of approximately 204 investor-owned utilities (IOUs) which supplied about 76 percent of the retail electricity market; the balance is provided by about 3000 public power systems including rural electric cooperatives and publicly owned government corporations (see table 3B-1). Traditionally, each retail electric supplier has a monopoly franchise to serve a specific geographic area. Some firms are vertically integrated, i.e., own and operate all phases of production, transmission and distribution of power, and others are limited to only one phase.

Roughly 30 percent of the IOUs are part of 14 major public utility holding companies in which virtually all phases of operation and planning of utilities within the holding company are interconnected and coordinated to function as a single integrated system. In 1981 IOUs accounted for about 77 percent of total U.S. generating capacity and served about 76 percent of all U.S. customers.

Most municipal systems purchase power at wholesale rates then resell it through distribution networks; several hundred municipal utilities are involved in generation but account for less than 4 percent of total U.S. electricity generation.

Rural electric cooperatives tend to be partially integrated operations, i.e., providing some internal generation but purchasing most of their power from IOUs or Federal power projects; generation by rural electric coops also accounts for less than 4 percent of total electricity generation nationwide.

Most government-owned power projects (Federal, State, and local) generally operate generation and transmission facilities, providing power to retailers at wholesale rates. Several government-owned systems provide retail service but while government systems provide nearly 15 percent of the nation's total electricity generation, they serve less than 1 percent of the Nation's retail customers.

Table 3B-1.—Selected U.S. Electric Utility Industry Statistics, 1981

Type of utility	Number in each group	Number of customers		Sales		Operating revenues		Installed capacity		Generation	
		Millions	Percent	Billion kWh	Percent	Billion dollars	Percent	Gigawatts	Percent	Billion kWh	Percent
Investor-owned	204[a]	71.8	76.2	1,634.2	76.1	102.3	76.6	490.9	77.3	1,786.0	77.8
Cooperatives	986	9.7	10.3	146.8	6.8	11.8	8.8	18.4	2.9	73.3	3.2
Municipals	1,898	11.5	12.2	261.1	12.2	13.0	9.8	35.2	5.5	80.7	3.5
Federal	41	[b]	[b]	45.1	2.1	5.0	3.8	61.0	9.6	232.2	10.1
Power districts and projects[c]	144	1.2	1.3	59.3	2.8	1.3	1.0	29.5	4.7	123.1	5.4
Totals	3,273	94.2	100.0	2,147.0	100.0	133.5	100.0	634.8	100.0	2,295.0	100.0

NOTES: Totals may not equal sum of components due to independent rounding; inconsistencies in the data are due to nonuniform sources.

[a] Class A and B utilities only (Class A utilities have annual electric operating revenues of at least $2.5 million; Class B utilities have annual electric operating revenues of at least $1 million but less than $2.5 million).

[b] Less than 0.4.

[c] Power districts and projects include State and county systems.

SOURCE: U.S. Department of Energy, Energy Information Administration, *Historical Financial Analysis of the Investor-Owned Electric Utility Industry* (Washington, DC: U.S. Government Printing Office, February 1984), DOE/EIA-0443.

industry as a whole, "avoiding any significant capital expenditures under present (financial) circumstances is a prudent business decision . . .," and while such capital aversion could result in noneconomic generation of electricity, it was viewed as the optimal strategy of least near-term risk. The degree to which new technologies are perceived to contribute simultaneously to long-term, cost-effective supply (or the equivalent in terms of demand reduction or shifts to non-peak times) as well as to short-term improved cash flow (due to shorter lead-time and smaller scale additions) could strongly influence their market penetration by the year 2000.

Table 3-4.—Technology Risks for Electric Utility Decisionmakers

1. **Technical risk**: the probability that a new generator will fail to come on-line at its anticipated capacity rating.
2. **Lifetime risk**: the probability that a new generator's lifetime will be significantly shorter than anticipated due either to technical problems or regulatory decision problems.
3. **Cost risk**: the probability that a new generation technology will cost significantly more to construct or operate than anticipated.
4. **On-time completion risk**: the probability that a technology will not come on-line when anticipated because of technical or regulatory problems.
5. **Lead-time risk**: the probability construction end time will be longer than planned. One problem is that events change such that the probject will no longer be needed or economically viable.
6. **Obsolescence risk**: the probability that a given technology will be economically obsolete prior to its planned lifetime. This is analogous to the lifetime risk and could result from fuel cost changes or new technologies being introduced, etc.
7. **Third-party ownership risk**: the probability that a generator owned by a third party will become unavailable to produce electricity for any reason related to the ownership by a third party, e.g., bankruptcy of the corporate entity owning a cogeneration facility so that the steam no longer exists and the facility is uneconomic without the steam demand.
8. **Reliability and performance risk**: the probability that a particular technology will be significantly less reliable than planned.

SOURCE: Modified from Edison Electric Institute (EEI), *Strategic Implications of Alternative Electric Generating Technologies* (Washington, DC: EEI, April 1984).

As utilities emerge from the financially stressed period of the 1970s and early 1980s, the tradeoffs between financial performance and the ratepayers' burden will be a subject of continuing debate that may affect the structure of the industry itself.[22]

The Current Context for Alternative Investments

Most utilities have been forced by economic and regulatory uncertainties to broaden the scope of their analysis of future investments, but this has not yet led, in most cases, to investment in new generating technologies.

A 1982 EPRI survey of member utilities[23] posed the question of what strategic options were considered likely in the event of limited capital availability over the next decade. Options involving new technologies fell well down the list of priorities, behind strategies such as increased conservation, deferral of retirements, rehabilitation of existing plant,[24] and increased participation in joint ownership of large conventional plants. The survey did suggest, however, that utilities are considering new technologies as an option to pursue in the event of unexpected contingencies and that "utilities revealed an increased willingness to consider a host of new technologies for generation before the end of this century."

Some utilities[25] think that there are three major contingencies that could more or less significantly affect the relative attractiveness of new supply technologies over the next decade:

- **Sudden increases in demand growth.**—Demand growth in the United States in 1983 was 1.9 percent and in 1984 it was 4.6 percent; demand predictions for the next decade vary from 1.5 to 5 percent.
- **Major reductions in allowable pollution emissions.**—Acid rain and other legislative initiatives could alter the kinds of coal-burning technologies and fuels used over the next decade.
- **Limited availability of petroleum.**—While the shortages and price increases of the 1970s prompted considerable shifts away from oil in U.S. electric power production, over 10 percent of the Nation's installed capacity is still oil-fired (see figure 3-7 earlier). Any dramatic changes in oil availability will affect the rate at which oil use declines in power generation. This issue is discussed in depth in a recent OTA assessment.[26]

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[22] On one hand, some economists argue that a solution to the utility industry's financial problems over the long term rests in deregulating portions of the power generation side of the business; on the other hand, others (e.g., U.S. Department of Energy (DOE), Report of the Electricity Policy Project, *The Future of Electric Power in America: Economic Supply for Economic Growth* (Washington, DC: National Technical Information Service, June 1983), DOE/PE-0045) argue that agglomeration of existing firms into larger regional entities addresses the financial problems more efficiently.

[23] Taylor Moore, et al., Electric Power Research Institute (EPRI), Planning and Evaluation Division, "Plans and Perspectives: The Industry's View," *EPRI Journal*, vol. 8, No. 8, October 1983, pp. 14-19

[24] Although AFBC retrofits of existing units involves a new technology; this option is being pursued aggressively by many utilities.

[25] For example, Southern Company Services, Inc., Research and Development Department, "Assessment of Technologies Useful in Responding to Alternate Planning Contingencies," unpublished, December 1983.

[26] U.S. Congress, Office of Technology Assessment, *U.S. Vulnerability to an Oil Import Curtailment* (Washington, DC: U.S. Government Printing Office, September 1984), OTA-E-243.

In the more distant future three additional contingencies could change utilities' investment decisionmaking priorities:

- **Natural gas availability.**—There is still considerable uncertainty in the domestic resource base for natural gas, although optimism is growing.[27] If reserves are significantly greater than previous estimates suggest, then natural gas might once again become an attractive fuel for electric power generation, although this would require modifications to the Fuel Use Act.
- **Dramatic changes in interest rates.**—As discussed earlier, due to the industry's capital intensity, high interest rates have caused electric utilities much financial stress. Dramatic decreases in interest rates could dampen the current interest in short lead-time, modular design technologies relative to larger central station plants; however, it could stimulate the interest of nonutility producers in such technologies.
- **Significant technological advances.**—Although much less likely than in other industries such as communications or computers, breakthroughs in technology could improve the likelihood of utility adoption of new technology over the next several decades. The opportunities for advances in the technologies considered in this assessment are discussed in chapter 4.

In addition, changes in Federal policies such as the tax system, PURPA, and the Powerplant and Industrial Fuel Use Act could have a significant impact on investment decisions as well; such changes are discussed in chapter 10.

While at the current rate of development extensive deployment of new technologies under any circumstances is unlikely in the 1980s, the first three contingencies are likely to affect utility decisionmaking with respect to new supply decisions; the latter three contingencies are not likely to affect utility decisions until the 1990s.

Trade-Offs in Allocated Investments and Strategic Planning

In light of economic and regulatory uncertainties surrounding the industry, many utilities are now considering, along with traditional central station powerplants (including joint ventures in such plants with other utilities), such options as dispersed generation, increased levels of purchased power, load management (or other end-use related actions), diversification into entirely new businesses (see figure 3-1 earlier), and new generating technologies as possible investments.

With an expanded spectrum of investment alternatives along with an uncertain decision environment, the problem then becomes one of comparing options that differ considerably in terms of production characteristics as well as in terms of financial risk and return;[28] for example, how does one compare a kilowatt of peak-load reduction achieved through load management to a kilowatt of new capacity from wind power?

If, for the moment, one takes the quality of service to be provided by a given utility as a prescribed constraint, as utilities have traditionally done, investment decisions hinge on the relative importance of the remaining objectives, namely minimizing the ratepayers burden and maintaining financial health. In recent years in the electric utility industry, as implied in the last section, the latter objective has taken on added complexity.

Generally, a utility strives to earn a rate of return at least equal to its cost of capital. Therefore long-term **profitability** could be defined as the difference between the return on equity (ROE) and the cost of capital[29] (k). Short-term cash flow implications of new investments have emerged as important concerns for many utilities in recent years, i.e., a utility must generate enough cash flow to maintain operations. Therefore, **sustainability** could be defined as the difference between funds generated and funds used at a given time.

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[27] OTA, *U.S. Natural Gas Availability: Gas Supply Through the Year 2000*, op. cit., 1985.

[28] Discussed in detail in D. Geraghty, "Coping With Changing Risks in Utility Capital Investments," unpublished paper, Electric Power Research Institute, February 1984.

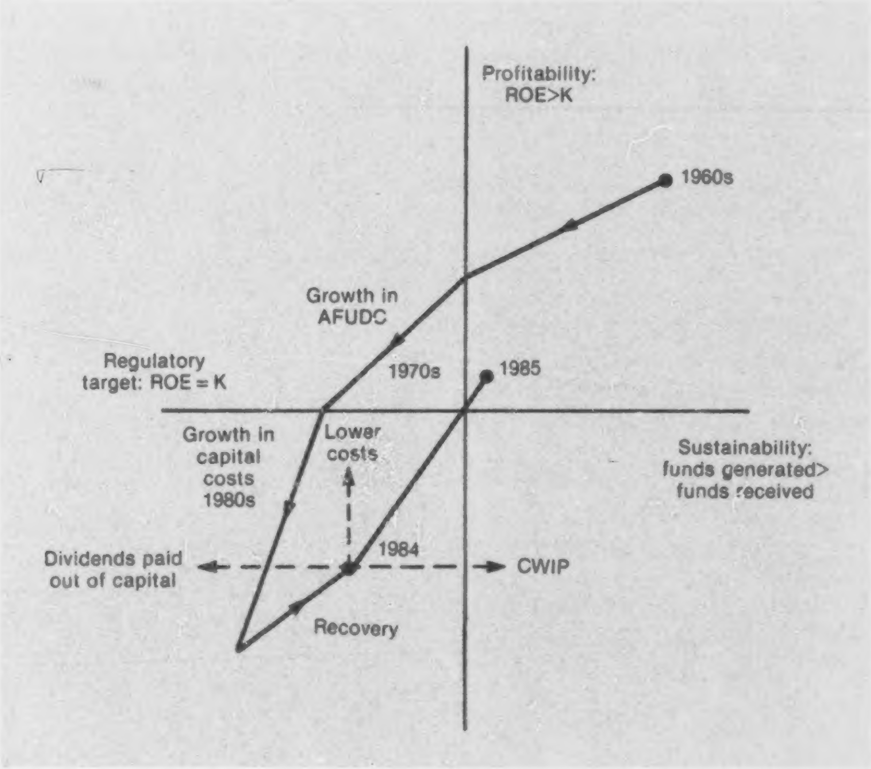
[29] If a utility's rate of return equals its cost of capital, stockholders still earn a competitive return; see D. Geraghty, "Coping With Risk in the Electric Utility Industry: The Value of Alternative Investment Strategies," *Second International Mathematics and Computer Society (IMACS) Symposium on Energy Modeling and Simulation*, Brookhaven National Laboratory, New York, Aug. 27, 1984.

The above definitions of profitability and sustainability are used in figure 3-15 to show the financial performance of utilities over the last two decades. If profitability is measured on the vertical axis and sustainability on the horizontal axis, the regulatory target is the origin, i.e., where return is equal to the cost of capital and where funds generated equal the funds received. In the 1960s, utility investments were both profitable and sustainable. With the precipitous rise in fuel prices in the early 1970s, investments became less sustainable as production costs became unexpectedly higher. With the increase in the share of earnings earmarked as funds used during construction (AFUDC), investments also became less profitable. In the 1970s the cost of capital increased further to the point where this industry could be considered both unprofitable and unsustainable. Current utility steps to increase profitability include requests for increases in allowed rate of return and efforts to reduce cost; steps to improve sustainability include requests for CWIP costs to be included in the rate base and avoidance of new construction projects.

Financial Criteria for Investments in Capacity

Utilities concerned about both short-term sustainability and long-term profitability of their operations can evaluate investment options in terms of their impact on a number of measurable pa-

Figure 3-15.—Profitability-Sustainability in Electric Utilities


Profitability: ROE>K
1960s
Growth in AFUDC
Regulatory target: ROE = K
1970s
1985
Growth in capital costs 1980s
Lower costs
Sustainability: funds generated> funds received
1984
Dividends paid out of capital
CWIP
Recovery

SOURCE: D. Geraghty, "Coping With Risk in the Electric Utility Industry: The Value of Alternative Investment Strategies," paper presented to the Second International Mathematics and Computer Society Symposium on Energy Modeling and Simulation, Brookhaven National Laboratory, New York, Aug. 27, 1984.

rameters that relate either directly or indirectly to sustainability and profitability. These parameters include the debt service coverage, return on equity, percent internal cash generation, and growth in earnings.

For example, an important parameter used in evaluating future cash flow implications is the debt service or interest coverage ratio which reflects the ability of the utility to repay its debt obligations and is a crucial factor in determining a utility's bond rating.[30] Table 3-5 demonstrates relationships between interest coverage ratios, utility bond rating, and average cost of these bonds. In this connection, year-to-year cash flow will fluctuate least when new generating plants are built in small increments and with short lead-times. Therefore, a utility aiming for a stable debt service coverage ratio could choose not to build long lead-time, large powerplants even when their cost per unit power may be less than the smaller plants because of engineering economies of scale (see chapter 8).

Prior studies give some insights into the tradeoffs between short lead-time, smaller scale additions to generating capacity and long lead-time, large powerplants. Ford and Youngblood[31] show that utilities that build plants with short lead-times can maintain a lower ratio of capacity under construction to installed capacity, when year-to-year changes in demand growth are very unpredictable. A lower ratio of capacity under construction would, in turn, allow a higher debt service coverage ratio. (Short lead-times for purposes of this analysis were defined as 1 to 2 years planning and permitting and 3 to 4 years construction.)

In a similar study Behrens[32] shows that nuclear plants built in units of 400 MW to follow demand growth closely allowed debt coverage ratios to be maintained at more than 3.0 throughout the planning horizon of a sample 7,000 MW utility. On the other hand, if capacity is added in nuclear units of 1,200 MW, the debt service coverage ratio falls to below 2.0 in the year just before the plant is brought on line. The simulation used in this study assumed the smaller nuclear units cost 12 percent more per kilowatt than the larger units.

Finally, a recent Edison Electric Institute analysis[33] found that a short lead-time technology, under a specified set of assumptions, would be preferred even if its capital cost (per unit) were up to 15 percent more than conventional technology (with equal operating costs). The value of short lead-times in the face of demand uncertainty is also discussed in more detail in appendix B of that study.[34] This issue of short versus long lead-time plants is discussed in more detail in chapter 8.

Table 3-5.—Electric Utility Debt Cost and Coverage Ratio Relationships

Coverage ratio	Bond rating	Average yield
3.0-3.5	AA	11.0%
2.5-2.75	A	11.3%
2.0	BBB	12.1%

SOURCES: Standard & Poor, "Standard & Poor's Bond Guide for 1983," 1983; and L. Hyman, *America's Electric Utilities: Past, Present, and Future* (Washington, DC: Public Utilities Reports, Inc., 1983).

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[30] The interest coverage ratio accounts for as much as 80 percent of a bond rating decision; see Rand Corp., *Electric Utility Decision Making and the Nuclear Option* (Santa Monica, CA: Rand Corp., 1977) or Standard & Poor, *Standard & Poor's Bond Guide for 1983* (New York: Standard & Poor, 1983).

[31] Andrew Ford and Annette Youngblood, "Simulating the Planning Advantages of Shorter Lead Time Generating Technologies," *Energy Systems and Policy*, vol. 6, No. 4, 1982, pp. 341-374; and Andrew Ford and Annette Youngblood, "Simulating the Spiral of Impossibility in the Electrical Utility Industry," *Energy Policy*, March 1983.

[32] Carl E. Behrens, "Economic Potential of Smaller-Sized Nuclear Plants in Today's Economy," Congressional Research Service paper prepared at the request of the Honorable Paul Tsongas, Washington, DC, Jan. 20, 1984, 83-621 ENR.

[33] EEI, *Strategic Implications of Alternative Generating Technologies*, op. cit., 1984.

[34] The scenario employed assumed a utility with a 5 GW peak demand, 6 GW of installed capacity, a load factor of 65 percent, total embedded capital (excluding CWIP) of $9.6 billion (average yearly cost of 10 percent—real discount rate) and embedded operating costs of 3 cents/kWh. The large plant was 1,000 MW with a 7-year lead-time at a cost of $2,000/kW (1980 dollars including interest during construction); small plants were 100 MW with installed costs of $2,200/kW.

A PORTFOLIO OF INVESTMENTS: BUSINESS STRATEGIES FOR THE 1990s

Introduction

The spectrum of alternative investments currently available to many utilities was briefly outlined in the last section. This section highlights the most important considerations in each of these options. As mentioned earlier, to the extent that new generating capacity is planned at all over the next decade, the industry as a whole appears to prefer traditional conventional power generation technologies (e.g., pulverized coal-burning technologies and combustion turbines) as the mainstay for strategic planning. The EPRI Annual Industry Survey for 1982, compared with the corresponding survey for prior years, did indicate, however, that more efficient use of energy has emerged more prominently in utility strategic plans than in previous years.

The EPRI survey also revealed an increased willingness to consider new generating technologies before the end of this century, particularly in light of the future contingencies (see previous section) that could affect the viability of conventional alternatives. In some utilities where available renewable resources are particularly attractive and plentiful, alternative technologies such as solar, geothermal, and wind may contribute significantly to future resource plans, but continued development of these technologies was viewed by the survey as benefiting only a handful of utilities over the next several decades.

Strategic options such as rehabilitation of existing plant and increased purchases of energy from neighboring utilities have emerged as important alternatives for utilities in the next decade, particularly where capital is in short supply.

Overall, therefore, in considering alternative strategic options for utilities, it is important to keep in mind that new generating technologies now appear to fall well down the list of priorities for most utilities, though interest in them is increasing as utilities plan for dealing with future uncertainty.

The business strategies of U.S. utilities, while actually a continuum, can be classified roughly into four basic, but not exclusive, categories:[35]

- **Modified grow and build strategy.**—A number of utilities have continued to view completion of large nuclear and coal plants initiated in the 1970s as their best option. Allowing for changes in the fuels used in generation, this is a continuation of the strategy of virtually the entire industry since its beginning. Some utilities, confident of renewed demand growth in the 1990s, are planning for continued expansion.
- **Capital minimization.**—Many utilities in the United States are now reacting to the current regulatory and financial climate in the industry with a strategy of minimizing capital expenditures by canceling plants both planned and currently under construction, increasing use of purchased power, participating in joint ventures if construction is necessary, selling existing capacity, rehabilitating existing plant, and increasing attention to load management. This strategy is designed to minimize corporate risk.
- **Renewable and alternative energy supply.**—A few utilities have embarked on a strategy of significantly increasing reliance on renewable energy sources as well as cogeneration from conventional sources in an effort to use small, modular plants to better track uncertain demand growth and reduce construction lead-times (other reasons are discussed later). The two large utilities (PG&E and Southern California Edison) that have made reliance on these sources an announced part of their strategy both come from California where renewable resources are relatively abundant and avoided energy costs are high. Many more utilities have initiated increased research and development programs in new

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[35] These categories are defined by S. Fenn, *America's Electric Utilities: Under Siege and in Transition*, op. cit., 1984).

technologies (discussed later). How many of these will go on to base a significant part of their strategic planning on alternative sources is uncertain.

- **Diversification.**—A majority of investor-owned utilities have begun to diversify their business interests by investing revenues in potentially more profitable ventures outside the electric utility business (see table 3-8). While the level of expenditures in such activities is as yet very small, a large number of utilities are exploring new business ventures on a small scale in areas such as real estate, telecommunications, oil and gas exploration, and business services.

Conventional Alternatives

The industry surveys cited earlier reveal that if more capital is available to electric utilities over the next decade and if emissions requirements are not tightened, conventional pulverized coal steam plants are generally the preferred investment option for future generation. The future of nuclear power remains clouded by management and regulatory problems as well as by technical and financial uncertainties. The EPRI survey found that "business decisions on new nuclear plants will remain clouded"until such uncertainties are resolved. This conclusion is supported by the recent OTA assessment on the future of nuclear power as well as by others.[36]

As discussed earlier, the cash-flow drawbacks of the long lead-time, large, conventional coal and nuclear plants as well as the potential costs of overbuilding due to uncertain demand growth have prompted utility interest in designs for these conventional technologies that permit installation of smaller, modular units (200 to 500 MW rather than 800 to 1,200 MW), even at a significant capital cost premium. In addition, in planning for circumstances such as increased regulation of pollution emissions, other utilities have also become interested in other modifications of conventional coal technologies. These include limestone injection, advanced coal cleaning techniques, improved scrubbers, and others.[37] Such modifications, while generally outside the scope of the current study, could significantly affect the relative attractiveness of new technologies under all the possible future contingencies cited earlier. Considered in this assessment are advanced coal conversion processes such as fluidized-bed combustion and integrated coal gasification/combined-cycle units.

Load Management and Conservation

One of the surveys cited earlier[38] found that 72 percent of the utilities they surveyed had initiated formal conservation programs and over two-thirds have started formal load management programs (see table 3-6). Fifty percent of these load management and conservation projects have appeared since 1980. Total investment in such programs is expected to increase dramatically over the next decade, particularly in load management. The survey suggests that "virtually the entire industry will have incorporated such activities in a formal way" (see table 3-6). Conservation options are not considered in this report but load management is discussed in chapter 5.

Plant Betterment

Many utilities have found it useful to consider measures of rehabilitating existing generation capacity or improving maintenance to extend their useful lives.[39] Indeed, some studies have found a high correlation between maintenance expenditures, unit availability, and adjusted return on equity, i.e., the difference between the earned return and bond yields.[40] Moreover, as life extension options are reviewed more carefully, many units operating at derated capacities, since they are approaching the end of their design lives, can be restored to their original output and more (up to 10 percent) with improved heat rates and overall efficiencies.[41] Some current research[42]

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[36] OTA, *Nuclear Power in an Age of Uncertainty*, op. cit., 1984; or Scott Fenn, *The Nuclear Power Debate: Issues and Choices* (New York: Praeger Publishers, 1981).

[37] See the Southern Co. Services report cited earlier.

[38] Cogan & Williams, Investor Research Responsibility Center, op. cit., 1983

[39] Lee Catalano, "Utilities Eye Unit Life Extension," *Power*, vol. 128, No. 8, August 1984, pp. 67-68.

[40] A. Corio, National Economic Research Associates, research summarized in "First Annual Maintenance Survey," *Electrical World*, vol. 197, No. 4, April 1983, pp. 57-64.

[41] G. Friedlander, "Generation Report: New Life Available for Old T/G's and Boilers," *Electrical World*, vol. 197, No. 5, May 1983, pp. 87-96.

[42] Summary of ongoing research by Temple, Barker & Sloane, Inc. given in "Optimum Use of Existing Plant," *Utility Investments Risk*

Table 3-6.—Conservation and Load Management Programs of Leading Utilities[a]

Company	Generating capacity 1982	Projected annual increase in demand through 1992	Program adoption date(s)	Program costs in 1982 (000)	Projected megawatts saved through 1992
TVA	32,076	2.38%	1977	57,000	4,000
Duke Power	14,526	3.87	1975	NA	2,994
Florida P&L	12,865	3.5	1980	23,000	2,100
Pacific G&E	16,319	0.9	1976/77	84,000	1,871
Carolina P&L	8,085	3.0	1981	10,600	1,750
Houston L&P	12,966	2.6	1978/80	12,500	1,700
So Calif Ed	15,345	2.0	1972	46,154	1,500
Florida Power	5,899	1.0	1980	5,000	1,500
Public Serv E&G	9,023	1.3	1982	9,000	956
BPA	0	NA	1980	86,000	802
Jersey Cen P&L	3,371	1.5	1980	9,000	800
Alabama Power	9,194	2.59	1976	1,266	800
Penn El	2,736	2.0	1973	4,200	671
Los Angeles	6,749	1.7	1976	7,876	601
Oklahoma G&E	5,359	NA	1982	NA	600
Northern States	6,162	2.0	1979	10,000	600
Metropolitan Ed	2,144	1.85	1980	1,000	485
Texas P&L	7,904	5.1	1977/81	5,100	465
Detroit Ed	9,458	2.5	1968/81	13,000	450
Arizona PSC	3,522	2.3	1977	3,230	420
Kansas City P&L	2,774	2.3	1982	NA	412
Tampa El	2,495	2.7	1980	8,000	400
Penn P&L	6,470	1.5	1983	4,700	390
Consolidated Ed	10,564	1.0	1975	440	370
Utah P&L	2,751	NA	1977	10,440	318

[a] Survey asked utilities to respond under a controlled growth scenario.

SOURCE: Douglas Cogan and Susan Williams, *Generating Energy Alternatives: Conservation, Load Management, and Renewable Energy at America's Electric Utilities* (Washington, DC: Investor Responsibility Research Center, Inc., September 1983).

suggests that life extension programs could dramatically reduce future revenue requirements as well. These options are discussed in more detail in chapter 5.

Plant rehabilitation and life extension are likely to be very significant options over the next two decades for utilities with a significant fraction of aging plants. These prospects over the next two decades depend on the life times assigned to existing capacity. For example, with an assumed 30-year average plant life, over 200 gigawatts (GW) of replacement capacity will be required by the year 2000, but with an assumed 50-year life, only 20 GW would be required (see table 3-7). Overall in the United States, the prospects for plant rehabilitation or life extension are limited by the fact that over half of the U.S. generating capacity has been built since 1970. In addition, these prospects vary considerably by region (see chapter 7).

Increased Purchases

Interconnection among utilities has always been common in the electric power industry but in recent years bulk power transfers have increased dramatically. In fact, the total volume of bulk power transfers increased by a factor of 30 between 1945 and 1980 while total electricity production increased only by a factor of 10.[43] In general, bulk power purchases are undertaken by a utility if the marginal cost of production in an interconnected utility is less than it would cost for the buyer to produce that power itself. The most significant increases began to occur in the early 1970s as oil prices forced many utilities

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Analysis: Technical Newsletter, Electric Power Research Institute, Energy Resources Program, No. 2, February, 1984; also see H. Heiges and H. Stoll, "Benefits of Power Plant Life Extension in Today's Business Climate," *Proceedings of the American Power Conference*, 1983.

[43] U.S. Department of Energy, Energy Information Administration, *Interutility Bulk Power Transactions*, (Washington, DC: U.S. Government Printing Office, October 1983), DOE/EIA-0418.

Table 3-7.—Replacement of Powerplants: Selected Options

	Cumulative replacement capacity GW needed by:			
	1995	2000	2005	2010
If existing powerplants are retired after:				
30 years	155	230	395	510
40 years	55	105	155	230
50 years	—	20	55	105
If all oil and gas steam capability is retired as follows:				
All	152	152	152	152
Half	76	76	76	76
All oil and gas capacity above 20 percent of region (3 regions)	55	55	55	55
If average coal and nuclear availability slips from 70% to:				
About 65%	21	21	21	21
About 60%	42	42	42	42

SOURCE: U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984) OTA-E-216; this analysis shows the sensitivity to North American Electric Reliability Council data projected from 1983.

highly dependent on oil to seek lower cost power from less oil-dependent neighbors and, as a result, the ratio of power purchases and wholesale power sales to total electricity sales among utilities varies by region as discussed in chapter 7.

While there are many different types of bulk power transactions, most fall into one of three categories:

1. economy transactions that reduce operating costs by displacing the buyer's own higher cost power with lower cost power from a neighboring utility;
2. capacity transactions which permit a utility to claim additional generating capacity from a neighboring utility to supplement its own for a specified period of time (sometimes called firm power transactions); and
3. reliability and convenience transactions that are negotiated to improve system operation and reliability—e.g., emergency support.

Some utilities will clearly benefit over the next two decades from increased reliance on purchased power from neighbors that have excess coal-fired and hydroelectric capacity and adequate transmission capabilities, and this option is being actively pursued by utility resource planners. Moreover, Canada will be an increasingly important source of electricity, primarily hydroelectric power, for U.S. utilities in certain regions.[44] [45] The likelihood of increased bulk power transfers both within the United States and from Canada and Mexico will affect the comparative attractiveness of new generating technologies in some regions.

Diversification

Some researchers argue that diversification of electric utility investments to more profitable lines of business could greatly benefit the industry's overall performance.[46] Indeed, diversification has received increased attention across the industry as shown in table 3-8. Other studies have observed this trend as well.[47] While outside the primary scope of the current study, diversification could play an important role in the strategic planning of some utilities in the next decade since such a strategy seeks to realize so-called "economies of scope," i.e., a utility might be able to exploit existing assets to obtain cost advantages in nonutility lines of business. For example, billing and collection or engineering services for other businesses could build on the existing infrastructure already present in the utility. The regulatory response to diversification is as yet uncertain; the range of activities is limited somewhat by individual public utility commissions, the Public Utility Holding Company Act, and PURPA.

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[44] Although the limitations on transmission capacity will become a major issue in the decades to come; currently, for example, New England is negotiating firm power contracts with Canada because transmission capabilities exist while links with the Ohio River Valley which has excess generating capacity are limited.

[45] International trade agreements with Canada for firm power (as opposed to economy interchanges which have been routine for many years) have recently become an important issue on both sides of the border; see Diane DeVaul, et al., *Trading in Power: The Potential for U.S./Canadian Electricity Exchange* (Washington, DC: Northeast-Midwest Institute, September, 1984); "Trading in Power: A Binational Conference on Electricity Exchange," Lake Placid, NY, Sept. 6-7, 1984; D. Hodel, "Statement on Canadian Imports of Electricity," (statement read to the Northeast-Midwest Institute Conference on Trading in Power), Sept. 6, 1984; and R. Bourassa, *Power From the North* (Scarborough, Ontario: Prentice-Hall, 1985).

[46] Edison Electric Institute (EEI), *Business Diversification Activities of Investor-Owned Electric Utilities* (Washington, DC: EEI, 1985).

[47] D. Arthur and A. Harris, "Diversification in the Electric Utility Industry," unpublished paper, Portland General Electric Co., Corporate Planning Division, Portland, OR, January 1981.

Table 3-8.—Edison Electric Institute Business Diversification Survey[a]

Venture	Percent of total
Fuel development and exploration	26
Real estate	13
Energy conservation services	8
Cogeneration and small power production	5
Appliance sales and service	5
Project management and consulting	5
Fuel transportation	5
District heating	3
Land management controls	3
Computer software sales	3

[a] Based on 296 total responses.

SOURCE: "EEI Details Utility Diversification in New Report," *Electric Light & Power*, vol. 63, No. 6, June 1985, p. 18; Edison Electric Institute (EEI), *Business Diversification Activities of Investor-Owned Electric Utilities* (Washington, DC: EEI, 1985).

Developing Supply and Storage Technologies

The range of technologies considered in this assessment that may show promise in electric power generation through the 1990s are included in table 3-9. A detailed evaluation of the probable costs and performance of these technologies is given in chapter 4. Considered here are some of the generic characteristics of these technologies that might affect a utility's decision to adopt them or might encourage nonutility investment in them.

Table 3-9.—Developing Technologies Considered in OTA's Analysis[a]

Photovoltaics:
  Flat plate systems (tracking and nontracking)
  Concentrators
Solar thermal electric:
  Solar ponds
  Central receivers
  Parabolic troughs
  Parabolic dishes
Wind
Geothermal:
  Dual flash
  Binary (large and small)
Atmospheric fluidized-bed combustors
Integrated gasification/combined-cycle
Batteries:
  Lead acid
  Zinc chloride
Compressed-air energy storage (large and small)
Phosphoric-acid fuel cells (large and small)

[a] For description see box 2A, ch. 2 and ch. 4.

SOURCE: Office of Technology Assessment.

Most of the developing technologies listed in table 3-9 are small in scale relative to conventional alternatives; hence they generally have shorter lead-times and offer the following benefits:

- **Modularity.**—Modularity of units, both in construction and in duplication of plants at a single site, means that decisions to initiate new capacity additions can be made closer to the time the units are actually needed. As a result, there is more flexibility in both tracking highly uncertain demand growth and in bringing new capacity on line to correct for temporary undercapacity. Several of the new technologies considered in this assessment (see table 3-9) lend themselves to modular design—e.g., wind, photovoltaics, fuel cells, and IGCC. Utilities consider flexibility in periods of highly uncertain demand growth to be a primary motivation for examining new technologies.[48] Combustion turbines have traditionally been used by utilities to reduce their exposure to risk during periods of uncertain demand growth, but they involve very high operating costs and use of premium oil and gas fuels. The gas industry is, however, very optimistic about the future of combined-cycle plants using natural gas.
- **Less "rate shock."**—Rate increases can be moderate with small plants or units coming on line and entering the rate base. If demand growth is very large, however, many small plants or units will be required and "rate shock" could be even more severe since small plants or units of alternative technologies generally come at a capital cost premium. A similar rate shock through fuel adjustment clauses might be experienced with a strategy of using combustion turbines to meet such unpredicted, large demand growth.
- **Increased reliability.**—Generally speaking, smaller units permit maintenance of a smaller reserve margin since individual forced outages of smaller units have less impact, although if the system is mixed, i.e.,

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[48] W. Gould, "Development of Renewable/Alternative Resources of Electric Energy," unpublished, Southern California Edison Co., Rosemead, CA, 1983.

with some large and small generators, the reserve margin must cover the possibility of a forced outage of the large units. Moreover, the potential of this benefit is complicated if the small units are dispersed source generators as discussed in chapter 6.

- **Improved financial flexibility.**—The amount of capital tied up in construction is substantially reduced by employing short lead-time technologies. Security rating agencies are concerned when a utility incurs a significant "asset concentration risk," e.g., placing a large amount of capital at risk on a single project which could ultimately account for 50 to 60 percent or more of the utility's rate base but only 10 to 15 percent of its installed capacity.
- **Improved quality of earnings.**—Less capital tied up in construction translates into a lower level of AFUDC reported in a utility's earnings. This, in the eyes of investors, raises the quality of earnings since AFUDC is considered a "paper" earning.
- **Technology and fuel diversity.**—Diversity of fuel types and technologies employed by a utility reduces not only technological risk but also institutional risks such as the impacts of a coal strike or an oil supply disruption.

In addition, many new technologies offer environmental benefits as well as advantages of fuel flexibility, increased efficiency, the potential of reduced fuel transportation costs and, in many cases, the possibility of cogeneration. Moreover, if a small-scale technology is suitable for dispersed siting near load centers, additional benefits are possible:

- **Reduced transmission requirements.**—Siting closer to load centers reduces the need for transmission; large plants generally must be sited much further away. The potential level of transmission "credit" possible in small dispersed generating units has been the subject of much research.[49]
- **Improved quality of service.**—Outages can generally be serviced more quickly with dispersed generation available to be dispatched locally.
- **Improved area control.**—If decentralized sources can be coordinated with energy control centers (where power flow to load centers is controlled), the result will be better regulation of area control error and hence improved efficiency and quality of power (see chapter 6).

While all of these potential benefits are in many cases sufficiently attractive to warrant interest on the part of utilities, alternative technologies also pose complications for utility planners in addition to the risk of relying on new technology. These include:

- **Load dependence.**—The uncertainty associated with impact on the system load curve of dispersed generating sources is compounded by the fraction of this generation coming from intermittent alternative energy sources such as wind, solar, and low-head hydroelectric systems. Unlike conventional sources or fossil-based dispersed sources which are largely independent of load characteristics, alternative sources are often interdependent with load due to such factors as wind speed, solar energy flux, temperatures, steam flow, etc.
- **Nondispatchable generation and utility operations.**—As mentioned earlier, nonutility or customer-owned equipment (actually for both new as well as conventional technologies) operating under the provisions established by PURPA are not generally included in a utility's economic dispatch system. Most utilities have treated nondispatchable generation as an expected modification of the system load curve in the same manner as load management. As penetration of nondispatchable sources grows, however, utilities will need to account for them more explicitly in dispatching strategies.
- **Nonutility generation and capacity planning.**—As mentioned earlier, nonutility generation has traditionally been treated as a modification to the system load curve. If significant penetration of such generation is considered a possibility, as might be the case in a number of utilities, the capacity plan-

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[49] See, for example, S. Lee, et al., Systems Control, Inc., *Impact of Transmission Requirements of Dispersed Storage and Generation* (Palo Alto, CA: Electric Power Research Institute), December 1979, EM-1192.

ning process for these utilities could be affected. The attitudes of utilities toward nonutility generation varies markedly among utilities in terms of interconnection requirements and conventions for establishing of avoided cost rates. Interconnection requirements such as insurance, control and safety equipment, meters, and telecommunications equipment can all vary according to size of generating plant, approved design specifications or other factors (see chapter 6). Similarly, avoided cost rates vary according to procedures for capacity and energy credits, and availability of "payment tracking mechanisms" that permit nonutility generators to receive higher revenues in early years of the project, as is the practice at Southern California Edison. The ultimate contribution of nonutility generation to the overall U.S. power generating capacity depends on not only the performance of the technology and adequate financial incentives, but also on the evolving attitudes of utilities, especially as they apply to rates and interconnection with nonutility generation. Indeed, interconnection requirements alone can increase nonutility generation cost by over $1,000/kW for small systems.[50] Some work is now being done to incorporate nondispatchable technologies into long-term generation planning.[51]

- **Rate inequities.**—The possibility of rate inequities also presents a potential problem in the case of encouragement of a large penetration of nonutility generation. Rate requirements are estimated for various customer classes, e.g., residential, commercial, heavy industrial, etc., based on the total revenue requirements of the utility and the forecasted demand of each customer class (including time of day and cost of service considerations). A situation could arise whereupon the demand of a particular customer class is reduced by the implementation of end-use devices or third-party generation plants and, consequently, customer rates must be increased to meet fixed revenue requirements.[52] Potential rate inequities may result, particularly to those customers in an affected rate class who do not use the demand-reducing device.
- **Research and development and regulatory treatment.**—As we will see in chapter 4, most new generation technologies, today, are not yet cost competitive with conventional alternatives. For promising new technologies, part of the difference between current and mature costs represents the amortization of R&D expenditures. An often-used operational rule among many utility commissions, however, is to permit plants into the rate base only if they can generate power at less than full avoided cost.[53] The issue then becomes clear: to what extent will the less than full avoided cost benchmark inhibit the commercialization of new technologies? If such a benchmark is relaxed, to what degree should ratepayers share with the stockholders the burden of higher per unit capital costs, greater risk of lower reliability, possibility of complete plant failure, and possibility of shorter plant life associated with new technologies? Some studies suggest that relaxed treatment of the full-avoided cost benchmark is a prerequisite to significant penetration of many new technologies (at least for demonstration and early commercial units) in utilities over the next two decades.[54] This issue is discussed in more detail in chapter 10.

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[50] See U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-192; and U.S. Department of Energy (DOE), *Survey of Utility Cogeneration Interconnection Projects and Cost—Final Report* (Washington, DC: DOE, June 1980), DOE/RA/29349-01.

[51] As discussed in M. Caramanis, et al., "The Introduction of Nondispatchable Technologies as Decision Variables in Long-Term Generation Expansion Models," *Institute of Electrical and Electronic Engineers (IEEE) Transactions*, vol. PAS-101, No. 8, August 1982, pp. 2658-2667.

[52] This phenomenon occurred in 1973-74 in San Francisco with local water utilities. Regional droughts motivated the utilities to subsidize advertising campaigns and various end-use devices for water conservation. The resulting drop in demand was of such magnitude that the utilities were put in a position of having to increase rates to meet their revenue requirements.

[53] L. Papay, "Barriers to the Accelerated Deployment of Renewable and Alternative Energy Resources," unpublished, Southern California Edison Co., December 1982.

[54] Ibid.

Current Activities and Interest in Alternative Technology Power Generation

The Edison Electric Institute[55] has observed four degrees of current involvement (not mutually exclusive) in alternative technology power generation by U.S. utilities:

- **Use of alternative technologies as a substantial contributor to future resource plans.**—Some utilities which are historically highly dependent on premium fuels (and hence have a very high avoided cost rate), have significant demand growth, and have severe environmental and regulatory constraints on using conventional technologies have announced significant plans for reliance on alternative technologies. As mentioned earlier in the discussion, only two such U.S. utilities, namely Southern California Edison and Pacific Gas & Electric, have done so to date.
- **Use of alternative technologies as a response to uncertain load growth.**—Some medium demand growth utilities, in response to environmental and regulatory pressures, have included alternative technologies as "an important but small" buffer in future resource plans.
- **Use of unregulated subsidiaries for equity participation in cogeneration.**—Some financially sound utilities—e.g., Houston Lighting & Power—in areas with cogeneration potential have been permitted by utility commissions to invest capital in cogeneration ventures with industry to avoid loss of load, revenue, and earnings. This strategy is termed "reactive diversification" as opposed to "proactive diversification" which is aimed at improving stockholder return on equity.
- **Active research and development.**—Many utilities, are involved in long-term research and development with alternative generating technologies as a possible response to various contingencies discussed earlier that could limit the use of conventional generating technologies.

So far, the penetration of new technologies has been very small. A great deal has happened in the last several years, however, particularly in cogeneration. Most of this cogeneration is using conventional technology, but some are new technologies such as AFBC. In addition, wind, low-head hydroelectric, and biomass technologies are also contributing. For the technologies considered in this assessment we discuss the historical rate of development in detail in chapter 9.

SUMMARY AND CONCLUSIONS

The electric utility industry has experienced a period of considerable stress in recent years due to declining electricity demand growth; dramatically increasing fuel prices, construction costs and capital costs and heightened public demand for better control of air and water pollution and nuclear safety. The industry emerged from this period of stress with significant uncertainties, especially about future demand growth, and financially weakened. While utilities' financial health appears to be improving markedly, they are not returning to their pre-1970s business strategies.

Still facing a difficult and uncertain investment decision environment, utilities have had to expand the scope of strategic options they are willing to consider over the next several decades to include such strategies as rehabilitation of existing plant, increased purchases from neighboring utilities, increased conservation and load management efforts, diversification of investments to nonutility lines of business and, finally, a range of new generating technologies. Most utilities are only beginning to consider such alternatives to traditional large-scale, central-station, powerplants. In particular, conservation and load management are beginning to attract more attention in utility resource plans; and many utilities have plant life extension or rehabilitation projects underway. Similarly, in response to uncertain demand growth, mature smaller scale technologies are under close scrutiny. For the most part, smaller scale new technologies are under consideration primarily as a possible response to future contingencies such as oil supply disruption or imposition of stricter environmental controls on coal burning. There are a few exceptions, notably Southern California Edison and Pacific Gas & Electric in California. They have included substantial commitments to new technologies in their long-term resource plans.

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[55] Edison Electric Institute, op. cit., 1984.

To date, nonconventional technologies account for only a tiny fraction of the Nation's overall electric generating capacity, the new technologies' penetration of the market is likely to grow throughout the remainder of this decade and throughout the 1990s.

Nonutility involvement in new technologies is increasing steadily under the provisions of PURPA and the rate of development of new generating technologies over the next two decades may well hinge not only on the performance of these in nonutility applications but also on the evolving relationship between utilities, nonutility generators of power, and regulatory agencies.

Chapter 4

New Technologies for Generating and Storing Electric Power

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Chapter 4

New Technologies for Generating and Storing Electric Power

INTRODUCTION

A number of new technologies for generating and storing electricity are being developed as alternatives to large-scale, long lead-time conventional powerplants. Of increasing interest are technologies which are small scale and highly efficient, which are capable of using alternative fuels, and/or which impose substantially lower environmental impacts than conventional generating options.

This chapter focuses on new technologies which, while generally not fully mature today, *could figure importantly in the electric-supply technologies installed in the 1990s*. Not examined in detail are those technologies which already are considered technically mature or those which are very unlikely to achieve wide deployment during that time. Only grid-connected applications are considered. The chapter also does not examine closely technologies which recently have been covered in other OTA reports.[1]

The new technologies covered in this report are summarized in table 4-1. In table 4-2, the technologies are grouped according to size and application, along with their primary competitors. They range in size from units less than 1 MWe to units greater than 250 MWe. The technologies can be divided between those in which the electrical power production is available upon utility demand (dispatchable) and those where it is not. In the table, dispatchable applications are further broken down according to base, intermediate, and peak load applications. Among applications where the utility cannot summon electrical power on command are intermittent technologies (e.g., wind turbines and direct solar equipment), when they have no storage capacity, as well as any other technologies not controlled by utilities.

Table 4-1.—Developing Technologies Considered in OTA's Analysis[a]

- Photovoltaics:
  - Flat plate systems (tracking and nontracking)
  - Concentrators
- Solar thermal electric:
  - Solar ponds
  - Central receivers
  - Parabolic troughs
  - Parabolic dishes
- Wind turbines
- Geothermal:
  - Dual flash
  - Binary (large and small)
- Atmospheric fluidized-bed combustors
- Integrated gasification combined-cycle
- Batteries
  - Lead acid
  - Zinc chloride
- Compressed-air energy storage (large and small)
- Phosphoric-acid fuel cells (large and small)

[a] For description see box 2A, ch. 2 and table 3-9, ch. 3.

The chapter discusses estimates of the typical cost and performance of these technologies *in the 1990s*. The estimates and extensive references are presented in appendix A. In presenting the estimates, the chapter seeks to explain and justify them, and to point out the expected, most important determinants of the technologies' cost and performance during the 1990s. Technology-specific research and development (R&D) opportunities to accelerate the deployment of the technologies in the 1990s are also addressed.

The cost and performance estimates presented here are based on the current status of the technologies and the context within which they are developing. Information on technical, economic, political, and other areas was analyzed and interpreted. The levels of uncertainty which varied by technology are also discussed.

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[1] These include nuclear power, conventional technologies used in cogeneration, and conventional equipment which uses biomass; see p. iv of this report.

Table 4-2.—Selected Alternative Generating and Storage Technologies: Typical Sizes and Applications

Typical configurations in the 1990s

Installation size (MW)	Dispatchable applications[a]			Nondispatchable applications[b]	
	Base load (60-70% CF)	Intermediate load (30-40% CF)	Peaking load (5-15%)	Intermittent (w/o storage)	Others (not utility controlled)
Greater than 250 MWe	Coal gasification/ combined-cycle	Coal gasification/ combined-cycle	n.a.		
	Conventional coal				
51-250 MWe	Geothermal Atmospheric fluidized-bed combustor	Atmosphere fluidized-bed combustor Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (maxi CAES) Solar thermal (w/storage)	Solar thermal Wind	Atmospheric fluidized-bed combustor Solar thermal (w/storage)
	Combined-cycle plants	Combined-cycle plants	Combustion turbine		
1-50 MWE	Geothermal Atmospheric fluidized-bed combustor Fuel cells	Fuel cells Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (mini CAES) Battery storage Fuel cells Solar thermal (w/storage)	Solar thermal Wind Photovoltaics	Atmospheric fluidized-bed combustor Geothermal Fuel cells Solar thermal (w/storage) Battery storage Compressed air storage (mini CAES) Geothermal
			Combustion turbine		Combustion turbine
Less than 1 MWe				Solar thermal Wind Photovoltaics	Fuel cells Battery storage

NOTES: For each unit size and application, new technologies are shown above the dotted line and conventional technologies are shown below the dotted line.
CF = capacity factor and n.a. = not applicable

[a] Dispatchable technologies may not be utility-owned

[b] Note that nondispatchable technologies may serve base, intermediate, or peaking loads

SOURCE: Office of Technology Assessment

GENERATING TECHNOLOGIES

Solar Technologies

Introduction

In seeking ways to directly exploit the Sun's energy to produce electric power, two alternatives are being pursued. Solar thermal-electric technologies rely on the initial conversion of light energy to thermal energy; the heat typically is converted to mechanical energy and then to electric power. Alternatively, photovoltaic cells may be used to directly convert the light energy into electrical energy. Between the two technologies, many variations are being developed, each with its own combination of cost, performance, and risk, and each with its own developmental hurdles.

Most solar electric technologies promise noteworthy advantages over conventional technologies.[2] These include:

1. *Free, secure, and renewable energy source:* These are especially important attributes when contrasted with price and availability uncertainties of oil and natural gas.
2. *Widely available energy source:* Figure 7-11 in chapter 7 illustrates the distribution of the solar resource in the United States.

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[2] Note that some solar technologies may use a supplemental fuel such as oil, gas, or biomass. In such instances, the hybrid system will not have some of the advantages and disadvantages listed; and the system will possess some advantages and disadvantages *not* listed.

3. *No off-site, fuel-related impacts:* The delivery of solar energy imposes no environmental impacts off-site, unlike the delivery of conventional fuels which frequently require a series of steps (exploration, extraction, refining, transportation, etc.) which each impose environmental impacts quite distinct from those at the power plant site itself.
4. *No fuel supply infrastructure required:* The delivery of solar energy does not require the development of an ancillary fuel-supply infrastructure as is the case with conventional fuels. A solar plant can operate remotely at any site; a coal plant could not do so without the prior development of an infrastructure which extracts, refines, and transports the coal to the plant.
5. *Short lead-times.*
6. *Wide range of installation sizes.*
7. *Declining costs:* Many of the solar thermal systems are experiencing declining costs, a fact which reduces risk in any plans to invest in the technologies.
8. *Relatively small water needs: Some* of the solar technologies require little water beyond that used for cleaning.
9. *Little or no routine emissions:* Other than thermal discharges and other than run-off from washing operations, most solar technologies do not routinely emit large quantities of wastes into the air, water, or soil.[3]
10. *Siting flexibility.*

Though graced by many advantages, solar electric systems—like any other generating technologies—also have disadvantages. Among them are:

1. *Intermittent supply of energy:* Solar energy is subject to uncontrollable and sometimes unforeseeable variations. It is not always there when needed. Most obviously, it completely ceases to be available every day for extended periods (night) or its power is considerably diminished anytime clouds pass between the Sun and the surface of the Earth. In addition, seasonal and annual fluctuations in average solar radiation can be significant.[4] And these fluctuations put stress on hardware and can cause control problems.
2. *Capital intensive:* Current solar electric technologies are characterized by very high capital costs per kWe.
3. *Land extensive:* Solar systems use a lot of land per unit of power. Where land is expensive, land acquisition can greatly increase installation costs. Where solar concentrators are spread over a large surface area, soils and microclimates and local ecosystems can be affected.
4. *Water usage:* Some solar thermal systems routinely require large quantities of water; and all likely will require periodic cleaning. Where units are used in arid areas, this may be a problem.
5. *Exposure to the elements and to malevolence:* Many of the system components are fully exposed. They therefore suffer from erosion, corrosion, and other damage from the wind, from moisture (including hail) and contaminants in the air, and from temperature extremes. The systems also may be easy targets for vandals or saboteurs. For these reasons most solar electric installations are enclosed by fences, often with some kind of barrier for wind protection. And where reflective mirrors are used, they frequently are designed not to shatter and to withstand the elements. A permanent security force also may be required where the systems are deployed, but their land extensiveness makes security difficult.
6. *Cost and difficulty of access:* The likelihood that the systems will be built in remote locations raises problems relating to site access during construction and for maintenance. Transmission access may also be difficult or expensive to obtain.

Photovoltaics

Introduction.—A photovoltaic (PV) *cell* is a thin wafer of semiconductor[5] material which converts sunlight directly into direct current (DC) electricity by way of the photoelectric effect. Cells are grouped into modules, which are encapsulated in a protective coating. Modules may be connected to each other into panels, which then are affixed to a support structure, forming an array (see figures 4-1 and 4-2). The array may be fixed or movable, and is oriented towards the Sun. Any number of arrays may be installed to produce electric power which, after conversion to alternating current (AC), may be fed into the electric grid. In a PV installation, all the components other than the modules themselves are collectively termed the balance-of-system.

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[3] Disposal of the technology at the end of its useful lifetime may, however, create serious waste problems.

[4] It was reported, for example, that the solar flux at Solar One, a solar-thermal central receiver plant in California, has been 25 percent lower than in the base year (1976) used for planning purposes for the plant. This may be due to the increased atmospheric particulate load imposed by recent volcanic eruptions.

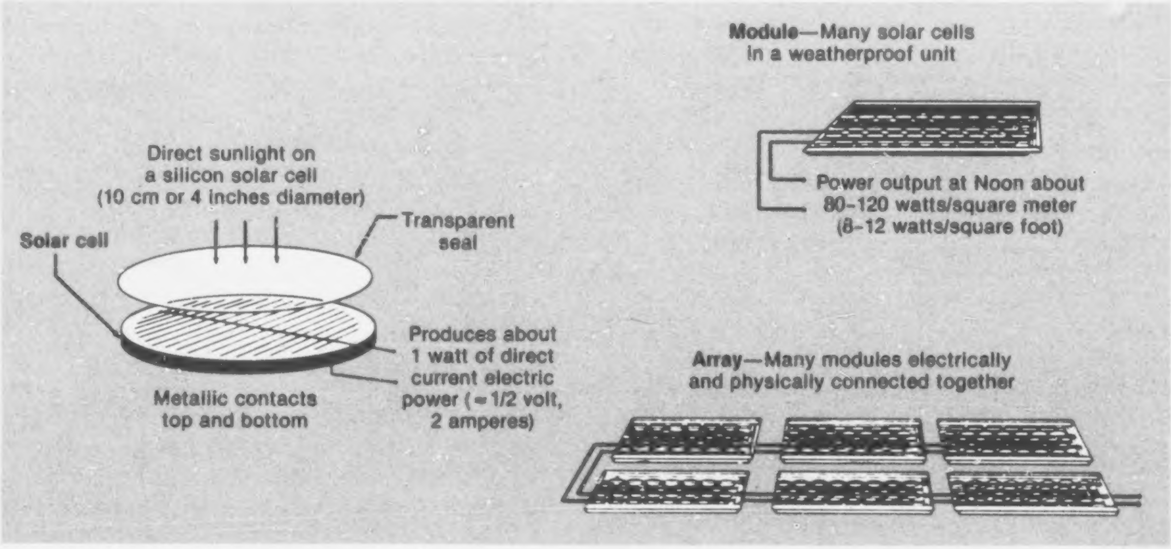
[5] A semiconductor is a material characterized by a conductivity lying between that of an insulator and that of a metal.

At present, PV systems are being pursued in many different forms. Each seeks some particular combination of cost and performance for the module and for the balance-of-system. In a concentrator module, lenses are used to focus sunlight received at the module's surface onto a much smaller surface area of cells (see figure 4-2); all available concentrator systems follow the Sun with two-axis tracking systems. A flat-plate module is one in which the total area of the cells used is close to the total area of sunlight hitting the exposed surface of the module. Various mechanisms such as mirrors can be used to divert light from adjacent spaces onto the exposed surface of the modules. Flat-plate systems may be fixed in position or may track the Sun with either single or two-axis tracking systems.

The parallel development of these two types of PV modules and systems reflects a basic technological problem: it is difficult to produce PV cells which are *both* cheap *and* highly efficient. Cheap cells tend to be inefficient; and highly efficient cells tend to be expensive. Some PV systems which are being developed for deployment in the 1990s are emphasizing cells which are relatively cheap and inefficient; such cells are used in flat-plate modules. Others are using a smaller number of high-cost, high-efficiency cells in concentrator systems.

In either case, if PV systems are to compete with other grid-connected generating technologies in the 1990s, their cost and overall risks will have to come down and their performance will

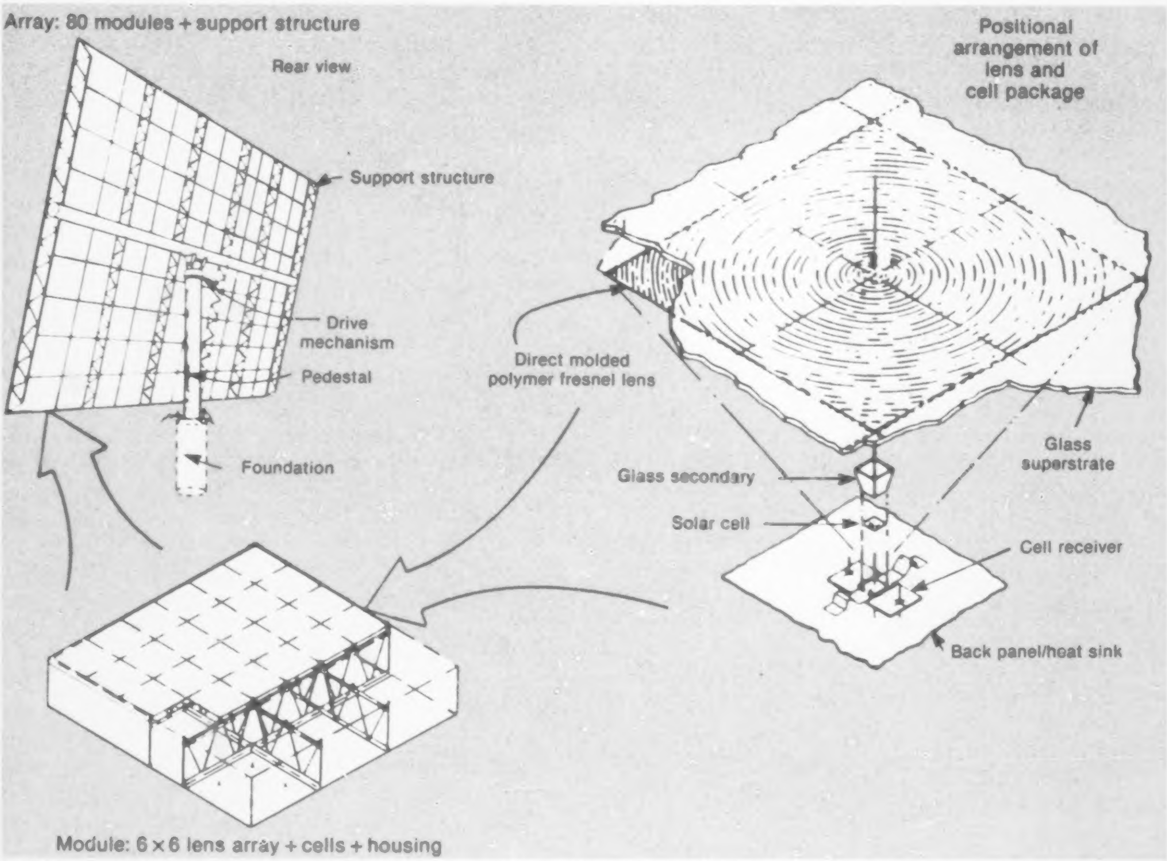
Figure 4-1.—Features of a Flat-Plate Photovoltaic System


Module—Many solar cells
in a weatherproof unit
Power output at Noon about
80–120 watts/square meter
(8–12 watts/square foot)
Direct sunlight on
a silicon solar cell
(10 cm or 4 inches diameter)
Solar cell
Transparent
seal
Produces about
1 watt of direct
current electric
power (≈1/2 volt,
2 amperes)
Metallic contacts
top and bottom
Array—Many modules electrically
and physically connected together

The basic hierarchy of a PV generator is the solar cell; the module, or group of cells connected in series or parallel; and the array, or group of modules connected in series or parallel.

SOURCE: Solar Energy Research Institute (SERI), *Photovoltaics: Technical Information Guide* (Golden, CO: SERI, 1985), SERI/SP-271-2452.

Figure 4-2.—Schematic of a Conceptual Design for a High Concentration Photovoltaic Array


Array: 80 modules + support structure
Rear view
Support structure
Drive mechanism
Pedestal
Foundation
Positional arrangement of lens and cell package
Direct molded polymer fresnel lens
Glass secondary
Glass superstrate
Solar cell
Cell receiver
Back panel/heat sink
Module: 6 x 6 lens array + cells + housing

SOURCE: Black & Veatch, Engineers-Architects, *Conceptual Design for a High-Concentration (500X) Photovoltaic Array* (Palo Alto, CA: Electric Power Research Institute, 1984) EPRI AP-3263.

have to improve. There is considerable disagreement over which particular PV system is the strongest contender for this market. Market penetration will depend on the current state of the particular variety of PV system; the potential for cost reductions and performance improvements; and on the reduction in risk perception among prospective investors in grid-connected installations.

At present, two types of modules appear to be the leading contenders. One is the flat-plate module based on tandem cells made from amorphous silicon; the other is the concentrator module, probably using crystalline silicon.

There are a number of reasons why the concentrator module could be the photovoltaic technology of choice in central station applications *in the near term*. The crystalline silicon cell is *relatively* well understood, as are the techniques for making such cells. The cells have been manufactured for many years, and information on cell performance after extended exposure to the elements is rapidly accumulating. Concentrator modules may offer a favorable combination of cost and performance in the Southwest, where early central station deployment probably will be greatest. And the prospects are good that cost and performance improvements can be made during the balance of the century. Many of the improvements do not appear to require basic technical advances but rather incremental improvements and mass production.

Flat-plate modules using amorphous silicon meanwhile are expected to continue to develop. But basic technical improvements must be made before extensive grid-connected deployment will occur. The current technology is too inefficient. Efficiencies must be improved, and the performance of the improved modules must be established over time and under actual conditions. This combination of technical improvements and the need to establish a clear, long-term performance record will take a substantial period of time. Because of this, amorphous-silicon flat-plates may not offer a superior choice for central station applications until the latter part of the 1990s or later. There is a small possibility, however, that rapid improvement in the cost and performance of amorphous modules is likely and that they will compete successfully with concentrators during most of the 1990s.

Regardless of technology, the commercial prospects for PV systems will depend heavily on continued technical development and the volume of production. Factors influencing either technical development or production levels therefore will strongly affect cost and performance in the 1990s.

The Typical Grid-Connected Photovoltaic Plant in the 1990s.—In the 1990s, central station applications probably will be favored over dispersed applications. Indeed, by May 1985, approximately 19 MWe of PV power in multimegawatt central station installations were connected to the grid in the United States—this was most of the grid-connected PV capacity in the country. This capacity was divided roughly equally between concentrator and flat-plate modules. By 1995, as much as 4,730 MWe could be located in such installations nationwide.[6] Capacity probably will be concentrated in California, Florida, Hawaii, Arizona, and New Mexico.[7]

In this analysis, it is assumed that the typical grid-connected photovoltaic system in the 1990s is a centralized photovoltaic system (see figure 4-3). Unless otherwise stated, the numbers referred to in this discussion are drawn from table A-1 in appendix A, where full references are provided. The discussion emphasizes the use of photovoltaic systems for the production of electricity alone. Such applications are expected to account for most central station photovoltaics in the 1990s. However, a significant share of photovoltaic systems may cogenerate both electric power and usable heat.

Given the modularity of photovoltaic systems, the rated capacity of central PV facilities in the 1990s will vary widely. An installation of 10 MWe is used here as a typical plant. This 10 MWe PV plant might occupy approximately 40 to 370 acres. The installation would consist of approximately 500 to 1,250 arrays, each of which would be supported by a structure resting on some kind of foundation. If the arrays are to track the Sun, they would require a motor and other tracking equipment. Currently, all central station PV plants use trackers, and evidence suggests that most central stations in the 1990s will too.[8]

Equipment also would be required to ground the arrays, to detect faults, and protect against faults. Direct-current wiring would connect the arrays to power-conditioning subsystems (PCS) which would control the arrays, convert the DC power produced by the arrays into a form suitable to the grid—constant voltage AC power—and regulate the switchgear.[9] (See figure 4-4.)

The environmental impact of large PV plants is likely to be extensive (see figure 4-5). During construction, impacts will result mostly from disruption of the soils, vegetation, and wildlife by the heavy machinery. Impacts after construction will relate to changes in the microclimate, ecology and appearance of the area from the simple presence of the large arrays and from routine maintenance. The latter could include activities

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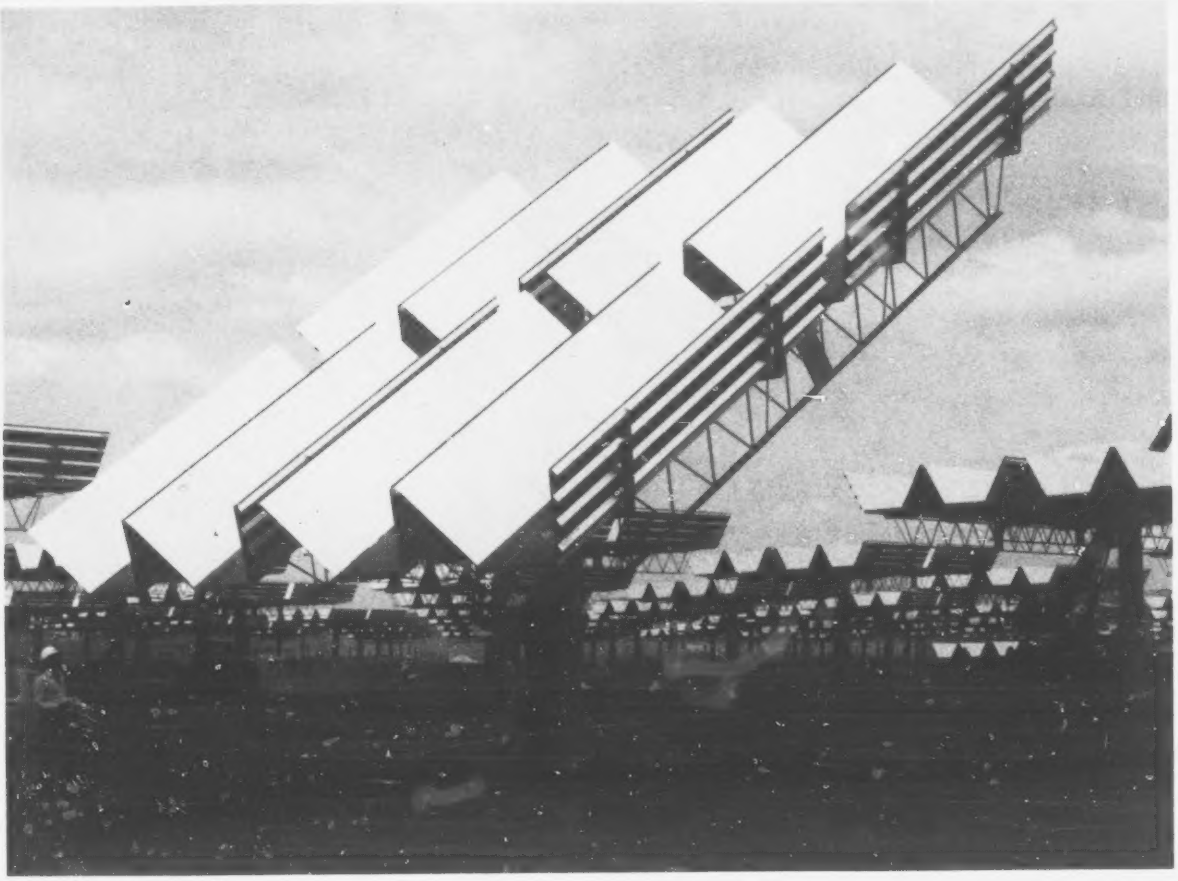
[6] This is the range provided by Pieter Bos (Polydyne Inc.), as estimated in a submission at the OTA Workshop on Solar Photovoltaic Power (Washington, DC, June 12, 1984) and discussed by Maycock and Sherlekar (Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 1995. A Strategic Technology & Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984), pp. 130-136.).

[7] Ibid.

[8] See for example: Gary J. Jones, *Energy Production Trade-Offs in Photovoltaic System Design* (Albuquerque, NM: Sandia National Laboratories, 1983), SAND82-2239. One reason for this is that trackers allow for higher electricity production and permit capital investment to be amortized more rapidly.

[9] For a good discussion of the basic components of a PV installation, see: Paul D. Sutton and C.J. Jones, "Photovoltaic System Overview," *Advanced Energy Systems—Their Role in Our Future: Proceedings of 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849251.

Figure 4-3.—A View of a Recently Installed Photovoltaic Central Station



SOURCE: ARCO Solar, Inc.

such as dust abatement measures, vegetation control efforts, and periodic cleaning of the modules

The lead-time required to deploy a PV plant is potentially quite short, perhaps 2 years—including planning, licensing, permitting, construction, and other elements. Construction itself should be quick and simple. Licensing and permitting should proceed very rapidly because many of the environmental impacts are low relative to those associated with conventional technologies. However, large PV plants will be new to most areas in the 1990s; and the land-extensive character of the technology raises problems which could engender controversy, leading to regulatory delays.

System Cost and Performance.—Operating availabilities of 90 to 100 percent are anticipated for the multimegawatt PV installation of the 1990s.[10] This will be affected primarily by the number of PCSs required and their quality. Most operating large PV systems today are characterized by operating availabilities below this—between 80 and 90 percent—usually as a result of problems with the PCSs. In order to reach the expected range of operating availabilities, PCSs must be developed which can operate reliably.

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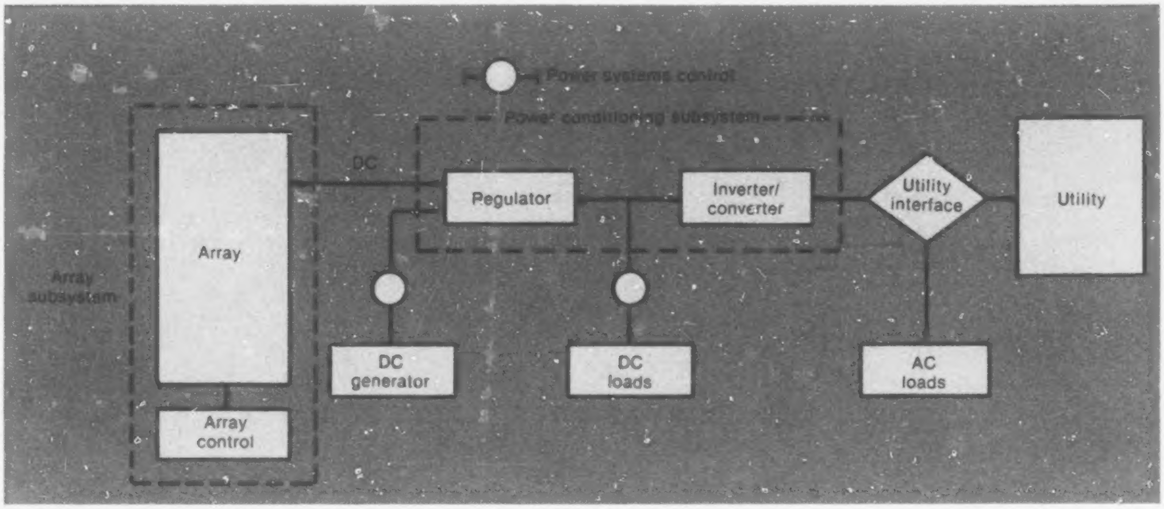
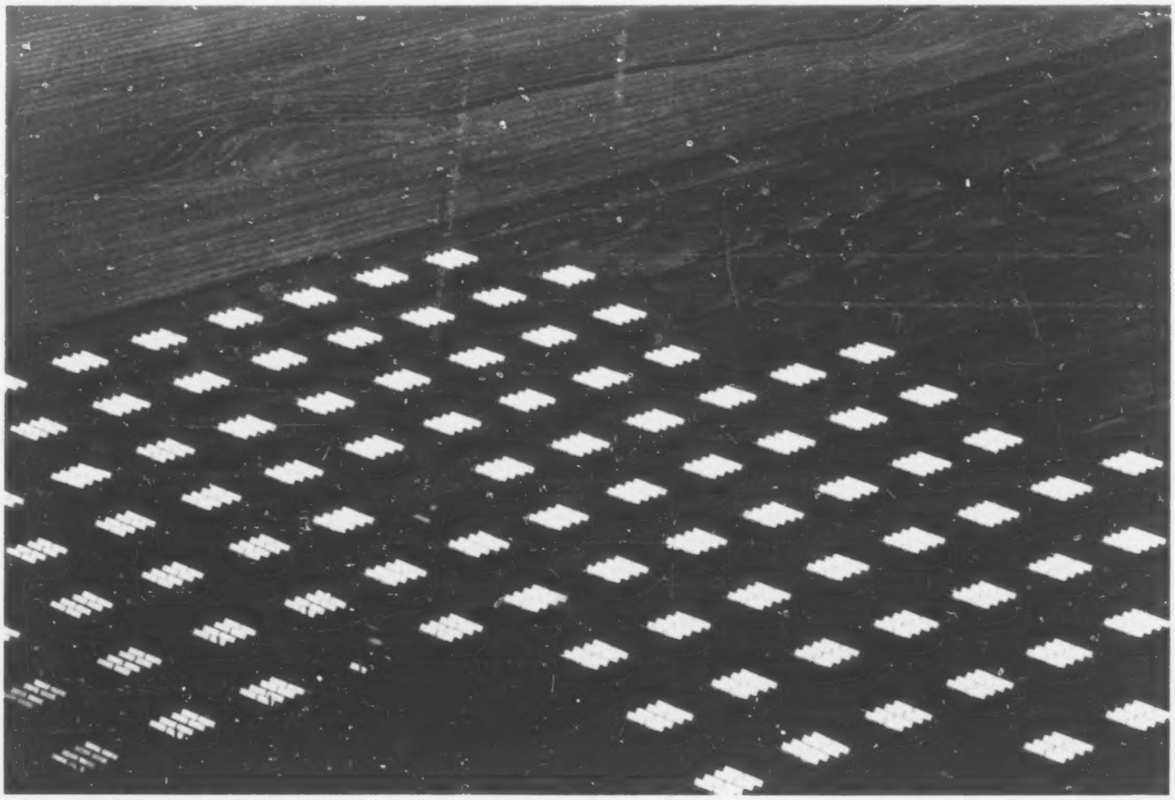
[10] Operating availability of individual arrays will be between 95 and 100 percent, depending mostly on the performance of trackers, if they are used. Recent experience with trackers suggests that their operating availabilities should not fall below that range.

Figure 4-4.—Block and Interface Diagram of a Photovoltaic Power System


Power systems control
Power conditioning subsystem
DC
Array
Array subsystem
Array control
Regulator
Inverter/ converter
Utility interface
Utility
DC generator
DC loads
AC loads

SOURCE: Paul D. Sutton and G.J. Jones, "Photovoltaic System Overview," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19 – 24, 1984* (San Francisco, CA: American Nuclear Society, 1984), Paper No. 849251.

Figure 4-5.—Aerial View of a Multi-Megawatt PV Central Station Powerplant Under Construction



SOURCE: ARCO Solar, Inc.

Such systems now are being developed and may be available during the 1990s.

Equipment lifetimes of up to 30 years are anticipated, but they will depend mostly on the lifetime of the modules, the trackers (if they are used) and the PCS, and the lifetimes for all three types of equipment are still uncertain. By far the most important component in this regard is the module; degradation and failures may seriously shorten its life.

Capacity factors will differ noticeably from system to system, depending on the general design features as well as on the location of the system and atmospheric conditions. In this analysis, capacity factors[11] for fixed flat-plate systems vary little—they range from 20 to 25 percent in Boston to 25 to 30 percent in Albuquerque. The capacity factors for tracking flat-plate systems are assumed to range from 30 to 40 percent,[12] though, this has yet to be verified nationwide. The capacity factor for concentrator systems varies by a larger margin by location—from 20 to 25 percent in Boston and Miami, to 30 to 35 percent in Albuquerque.

The modules and the balance of system (BOS) jointly determine capital costs and efficiency. Module cost and efficiency, as discussed above, depends on whether the system utilizes flat-plate modules or concentrator modules. Regardless of module or whether the array is fixed or tracking, BOS *efficiencies* are likely to fall within the same rough range. The costs of the BOS, however, will vary greatly, depending on whether or not a tracking system is used.

The typical multimegawatt flat-plate module PV station in the 1990s probably will produce electric power with an efficiency between 8 to 14 percent. Capital costs are expected to range between $1,000/kWe and $8,000/kWe in Albuquerque, and higher elsewhere in the country. Installations using concentrator modules should be more efficient—with a 12 to 20 percent efficiency. Capital costs for concentrator modules in Albuquerque should be between $1,000/kWe and $5,000/kWe; costs will be higher in areas with lower levels of direct sunlight.

Cost reductions and performance improvements in PV systems will require the deployment of highly automated processes capable of mass producing cells as well as efficiently producing other components, such as tracking equipment and lenses for concentrators.

Another important element of cell costs will be the cost of silicon. If cell costs are to be driven down, either the quantity of silicon consumed per kilowatt-electrical of cell produced must be reduced; or silicon costs must be lowered either through new production techniques or by an expansion of silicon production capacity. More material-efficient cells are being developed which require less silicon per kilowatt-electrical produced.[13] Efforts are also underway to develop silicon production processes which can produce low-cost silicon. There is a fair chance that these silicon production processes will be successfully developed and available in the 1990s.[14] And evidence indicates that the additional silicon production capacity will be built when needed.[15]

PV plants should have low operating and maintenance costs—probably ranging from 4 to 28 mills/kWh in the 1990s. These estimates are highly uncertain, though, and will only become more definite as more systems are placed in the field. Questions about module lifetimes, tracker problems, and difficulties with the PCS make operating and maintenance (O&M) cost projections uncertain.

Two other areas of uncertainty may increase O&M costs. The first is that dirt accumulating on the modules may reduce their efficiency.[16] Rain has been found to be an effective cleaner, but often the best areas for photovoltaics have little rain. With flat-plate systems, dirt does not seem to be as much of a problem as with concentrators. The second problem is wind damage. Most existing photovoltaics and solar thermal plants have suffered damage from wind blown sand, though methods to prevent this are being developed.

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[11] Capacity factor is the ratio of the annual energy output (kWe (AC)) of a plant to the energy output (kWe (AC)) it would have had if it operated continuously at its nominal peak operating conditions.

[12] OTA staff interview with D.G. Schueler, Manager, Solar Energy Department, Sandia Laboratories, Albuquerque, NM, Aug. 7, 1984.

[13] A good discussion of silicon and its importance as a driving force behind the development of alternative PV technologies can be found in: Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 1995. A Strategic Technology & Market Analysis*, op. cit., 1984.

[14] Leonard J. Reiter, *A Probabilistic Analysis of Silicon Cost* (Pasadena, CA: Jet Propulsion Laboratory, 1983), DOE/JPL/1012.

[15] Robert V. Steele, "Strategies On Poly," *Photovoltaics International*, vol. II, No. 4, August/September 1984, pp. 6-8.

[16] For example, in a module performance evaluation program conducted by the MIT Lincoln Laboratory and the Jet Propulsion Laboratory, "the greatest single cause of power loss has been soil accumulation." (Edward C. Kern, Jr., and Marvin D. Pope, *Development and Evaluation of Solar Photovoltaic Systems: Final Report* (Lexington, MA: MIT, 1983), DOE/ET/20279-240.

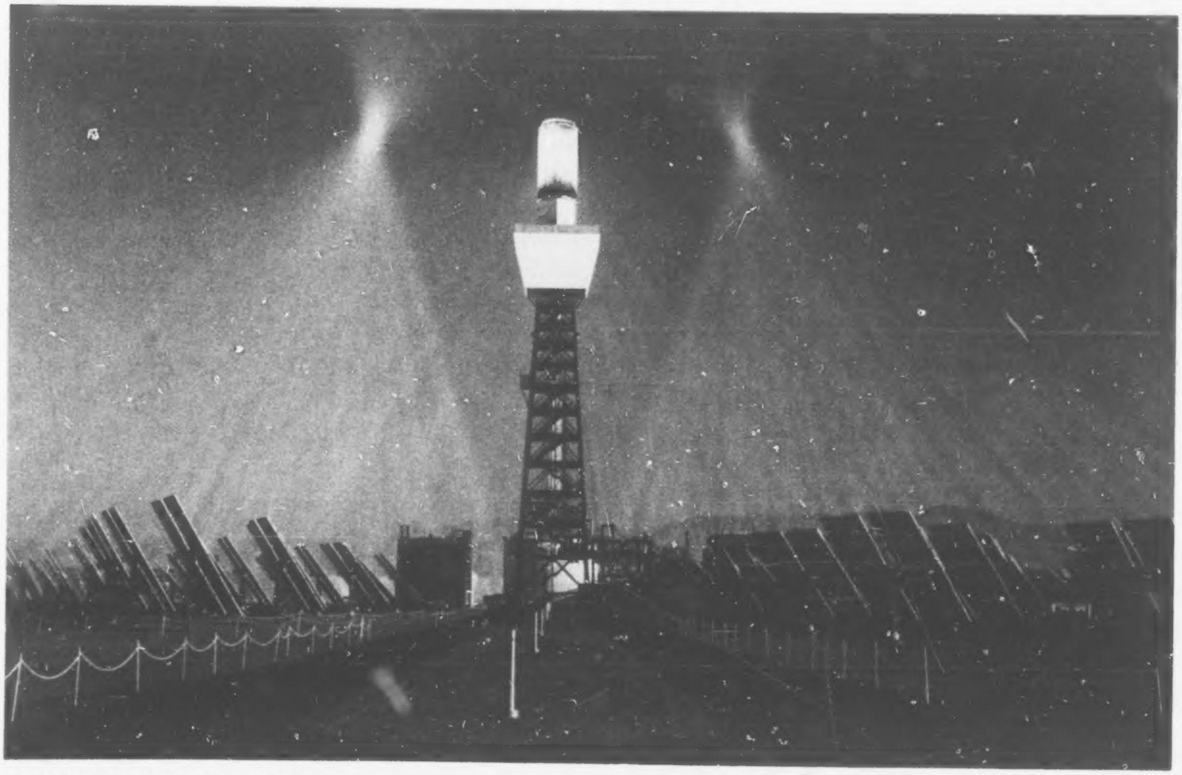
Solar Thermal-Electric Powerplants

Technology Descriptions.—Solar thermal-electric plants convert radiant energy from the Sun into thermal energy, a portion of which subsequently is transformed into electrical energy. Among the systems, there are four which, with some feasible combination of reduced costs and risks and improved performance, could be deployed within the 1990s in competition with other technologies and without special and exclusive Government subsidies. They are central receivers, parabolic troughs, parabolic dishes, and solar ponds. Brief descriptions of these technologies are provided below.

Central Receiver.—A central receiver is characterized by a fixed receiver mounted on a tower (see figure 4-6). Solar energy is reflected from a large array of mirrors, known as heliostats, onto the receiver. Each heliostat tracks the Sun on two axes. The receiver absorbs the reflected sunlight, and is heated to a high temperature. Within the receiver is a medium (typically water, air, liquid metal, or molten salt) which absorbs the receiver's thermal energy and transports it away from the receiver, where it is used to drive a turbine and generator, though it first may be stored.

Parabolic Dishes.—Parabolic dishes consist of many dish-shaped concentrators, each with a re-

Figure 4-6.—The Solar One Powerplant



SOURCE: Southern California Edison Co.

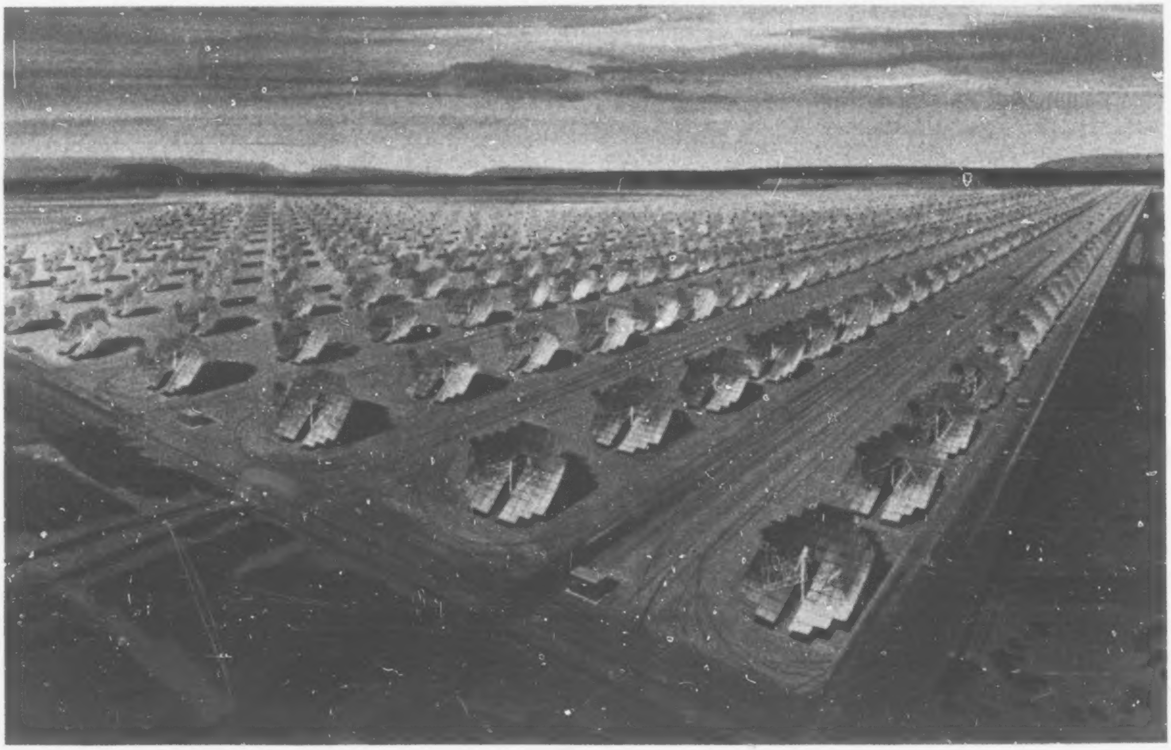
ceiver mounted at the focal point. The concentrated heat may be utilized directly by a heat engine placed at the focal point (mounted-engine parabolic dish); or a fluid may be heated at the focal point and transmitted for remote use (remote-engine parabolic dish). Each dish/receiver apparatus includes a two-axis tracking device, support structures, and other equipment (see figures 4-7, 4-8, and 4-9).

Solar Troughs.—With a parabolic trough, the concentrators are curved in only one dimension, forming long troughs. The trough tracks the Sun on one axis, causing the trough to shift from east to west as the Sun moves across the sky. A heat transfer medium, usually an oil at high temperature (typically 200 to 400° C), is enclosed in a tube located at the focal line. The typical installation consists of many troughs (see figure 4-10).

The oil-carrying tubes located at their focal lines are connected on each end to a network of larger pipes. The oil is circulated through the tubes along the focal lines, flows into the larger pipes, and is pumped to a central area where it can be stored in tanks or used immediately. In either case, it ultimately passes through a heat exchanger where it transfers energy to a working fluid such as water or steam which in turn is routed to a turbine generator. At the Solar Energy Generating units in southern California, the only large trough installations in the United States, the oil's heat is supplemented with a natural gas-fired combustion system to obtain adequate steam temperatures to drive the turbine. After passing through the steam generator. The oil is used to preheat water destined for the steam generator; the oil may be returned to the trough field.

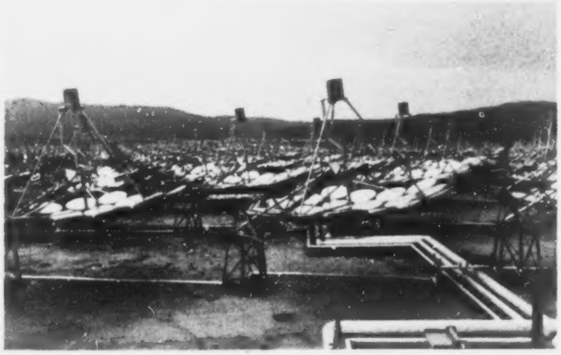
Solar Pond.—In an ordinary body of open water, an important mechanism which influences the thermal characteristics of the reservoir is natural convection. Warmer water tends to rise to

Figure 4-7.—An Artist's Conception of a Multi-Megawatt Parabolic Dish Installation



SOURCE: McDonnell Douglas Corp. brochure.

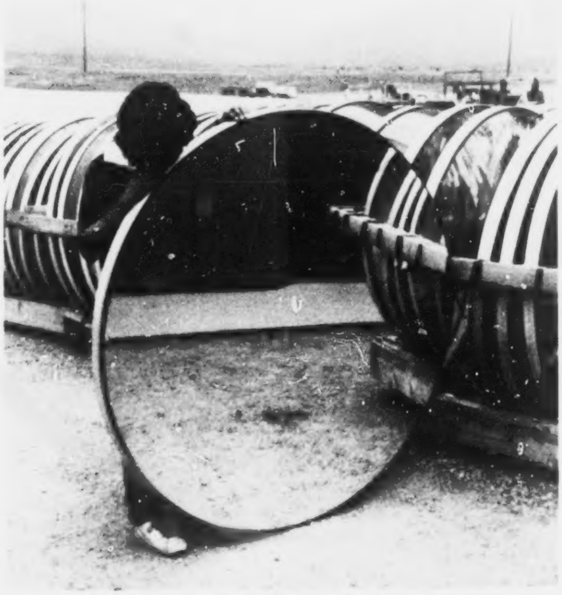
Figure 4-8.—View of the LaJet Energy Co.'s Solarplant 1 in Southern California



Note the extensive network of pipes which carry water and steam through the field.

SOURCE: OTA staff photo.

Figure 4-9.—An Employee of the LaJet Energy Co. Inspecting One of the 24 Mirrors Which Are Assembled Below Each Individual Receiver



The mirrors are made of hoops over which a sheet of reflective polymer is stretched.

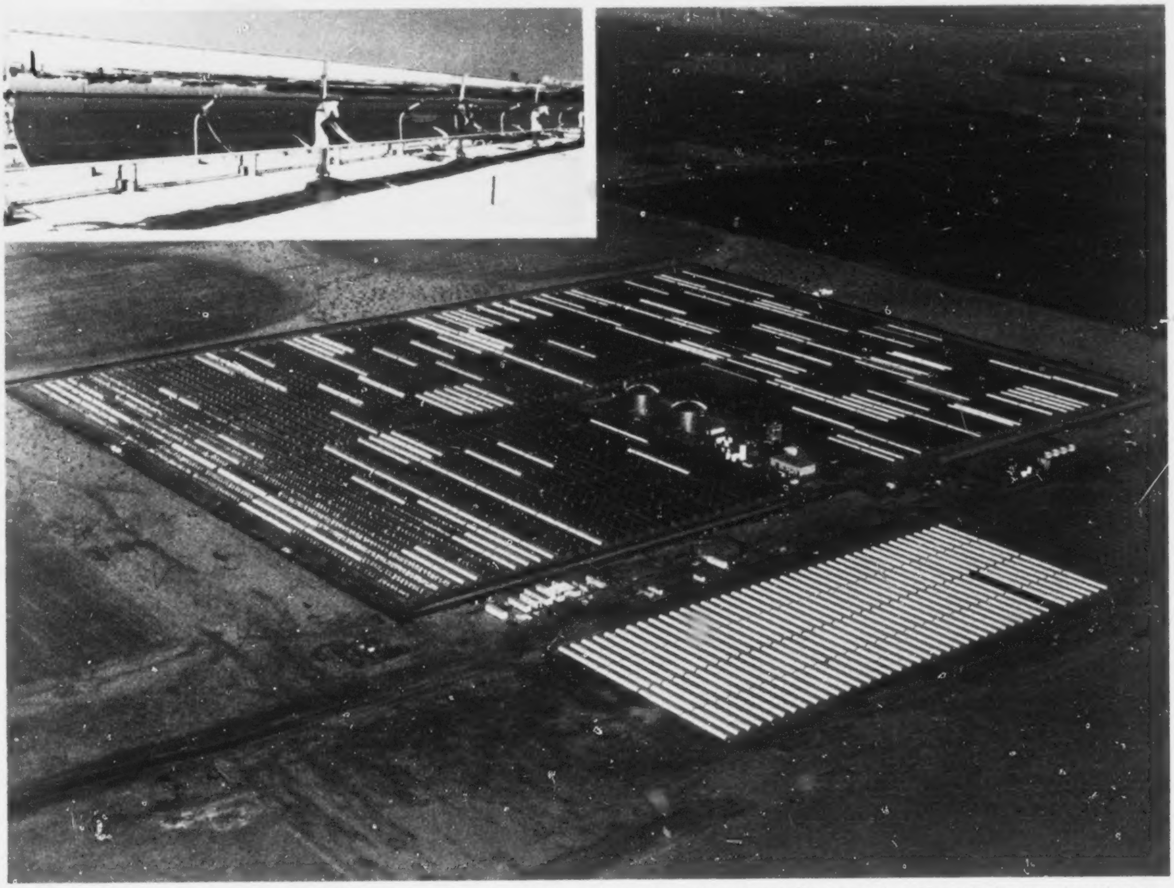
SOURCE: OTA staff photo.

the surface; and if the water is warmer than the ambient air, it tends to lose its heat to the atmosphere. A solar pond (see figure 4-11) is designed to inhibit this natural process. The creation of three layers of water, with an extremely dense layer at the bottom and the least dense layer at the top, interferes with the movement of warmer bottom waters toward the surface. Salt is used to increase the density of the bottom layer, forming a brine, to the point where its temperature can go as high as 227° F. The heat in this bottom layer can then be drawn off through a heat exchanger, where the brine transfers its heat to an organic working fluid which in turn can drive an engine to produce electric power.

General Overview.—Within most of the above mentioned technologies, many variations now exist or could exist. The discussion here is confined to those variations which appear to affect prospects for solar thermal-electric systems in the 1990s. The discussion is intended to be a brief survey rather than exhaustive examination of the technologies.

Each technology is characterized by a particular set of advantages and disadvantages (see table 4-3) which together define its prospects this century. All of the technologies share a principal disadvantage in that costs and performance are currently uncertain. The level of uncertainty can only be reduced sufficiently as commercial-sized units are deployed and operated. In some cases, research and development hurdles must still be solved before commitments are likely to be made to early commercial units. Until this occurs, the chances for widespread commercial application for any one technology during the 1990s are quite small, regardless of the technology's ultimate promise. At least one operating system is required to reduce cost and performance uncertainty to a level where it no longer is a primary impediment to extensive investment; and perhaps several units—including early commercial units—would be necessary. The time and expense associated with these early demonstration and commercial units are critical elements in determining the commercial prospects of the solar thermal technologies in the 1990s.

Figure 4-10.—Aerial View of the SEGS I Trough Solar Electric Plant (far side of the road)



On the near side of the road is the SEGS I-Plus system, presently under construction. **Inset:** Close-up view of parabolic trough collector

SOURCES: Southern California Edison Co. and LUZ Engineering Corp.

While the need to reduce uncertainty is of prime importance, efforts to improve cost and performance through continued research and development also could enhance the prospects for the technologies in the 1990s. The primary R&D needs are different for each technology though generally efforts directed towards the development of low-cost, durable, and efficient concentrators, receivers, and heat engines are most important.[17] Also very important will be the need for adequate data on the solar resource across the country.[18]

Solar Ponds and Central Receivers.—Neither solar ponds nor central receivers appear to require major technical breakthroughs before they can be commercially applied. But because no commercial-scale solar ponds or central receivers are now operating in the United States, because none are now under construction in this country, and because of the long lead-times expected for the installations, it will be very difficult to deploy enough demonstration and early commer-

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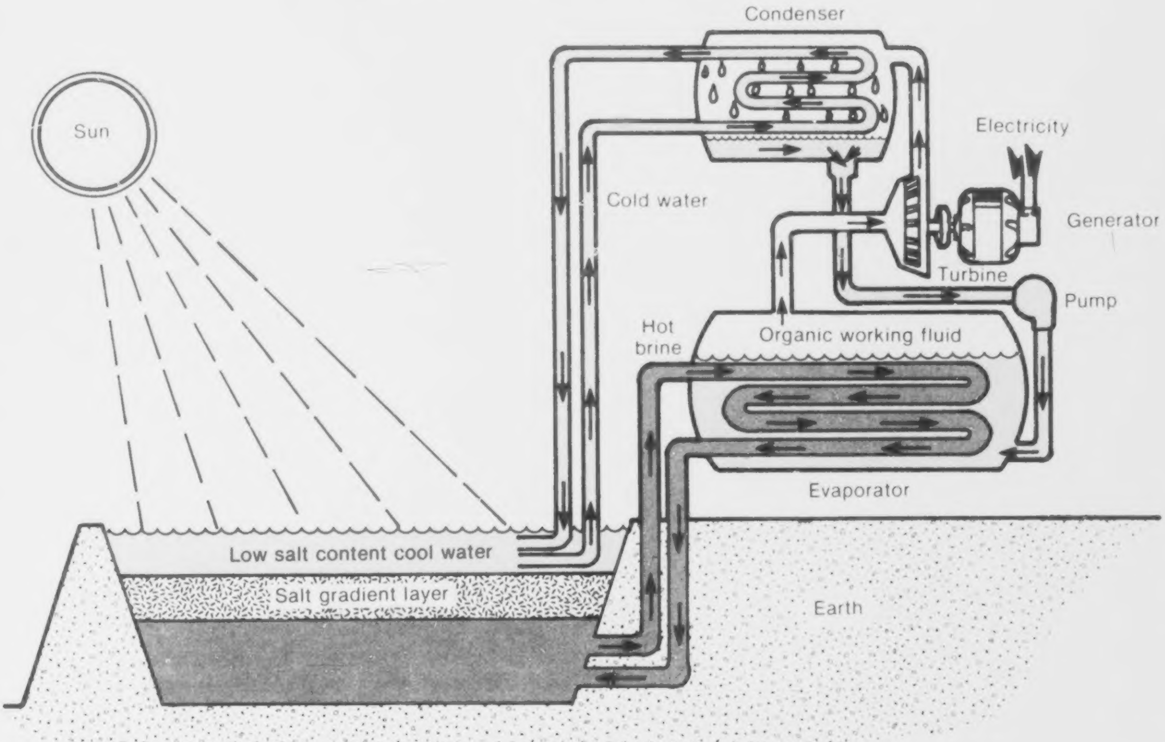
[17] More detailed information on R&D needs for solar thermal technologies can be found in Sandia National Laboratories, U.S. Department of Energy, *Five Year Research and Development Plan 1985-1989*, draft (Livermore, CA: Sandia National Laboratories, December 1984); and Edward I.H. Lin, *A Review of the Salt Gradient Solar Pond Technology* (Pasadena, CA: Jet Propulsion Laboratory, 1982), DOE/SF-2252-1.

[18] B.P. Gupta, *Solar Thermal Research Program*, Annual Research Plan, Fiscal Year 1985 (Golden, CO: Solar Energy Research Institute, 1984).

Figure 4-11.—Solar Pond Powerplant Concept


Condenser
Sun
Electricity
Cold water
Generator
Turbine
Pump
Hot brine
Organic working fluid
Evaporator
Low salt content cool water
Salt gradient layer
Earth

SOURCE: E. I. H. Lin and R. L. French, *Regional Applicability and Potential of Salt-Gradient Solar Ponds in the United States* (Pasadena, CA: Jet Propulsion Laboratory, 1982).

Table 4-3.—Advantages and Disadvantages of Solar Thermal Electric Systems

	Technology				
Characteristic	Solar ponds	Solar troughs	Parabolic dishes (mounted-engine)	Parabolic dishes (remote engine)	Central receiver
1. Demonstrated in U.S. at commercial scale?	No (−)	Yes (+)	Yes (+)	Yes (+)	No (−)
2. Privately financed plants now operating?	No (−)	Yes (+)	No (−)	Yes (+)	No (−)
3. Nonelectric/repowering/cogeneration market?	Yes (+)	Yes (+)	No (−)	Yes (+)	Yes (+)
4. Overall efficiency	very low (−)	low (−)	high (+)	low (−)	med (•)
5. Number of engines/kWe	low (+)	low (+)	high (−)	low (+)	low (+)
6. Degree of modularity	low (−)	low (−)	high (+)	low (−)	low (−)
7. Able to use indirect or diffuse sunlight?	yes (+)	no (−)	no (−)	no (−)	no (−)
8. Thermal storage capability of 1 hour or more?	yes (+)	yes (+)	no (−)	yes (−)	yes (+)
9. Supplementary fuel required?	no (+)	yes (−)	no (+)	no (+)	no (+)
10. Water requirements	high (−)	med (•)	low (+)	med (•)	med (•)
Total, all categories:					
+ (major advantages)	5	5	5	5	5
− (major disadvantages)	5	4	5	4	4
• (moderate advan/disadvan)	0	1	0	1	2
Total, categories 3-10:					
+ (major advantages)	5	3	4	3	4
− (major disadvantages)	3	4	4	4	2
• (moderate advan/disadvan)	0	1	0	1	2

SOURCE: Office of Technology Assessment.

cial units quickly enough to sufficiently reduce uncertainty about cost and performance. Furthermore, the expense of such early units is high enough that it is very unlikely that any entity or group of entities outside of government presently would invest in such units without special government incentives. In short, the time and expense associated just with reducing risks for these two technologies strongly mitigate against the provision of sizable amounts of electric power by the technologies within the 1990s. It is likely that only a sizable and immediate government intervention to encourage rapid deployment of demonstration units and subsequent units could reduce uncertainty to the point where it no longer is a major impediment to commercial investment in the 1990s.

Should such intervention occur and if the potential advantages of the solar ponds and central receivers are realized, both technologies offer favorable balances of advantages and disadvantages which could stimulate considerable private investment in the 1990s. Between the two technologies, the central receiver probably would be most widely deployed. Solar ponds must be located in areas where land, water, and salt are plentiful. Such sites are far less common than the sites available to central receivers, which require considerably less land, less water, and do not require such large quantities of salt. Siting options therefore are greater with the central receiver.[19]

Furthermore, the central receiver is a more mature technology. A 10 MWe (net) pilot facility, Solar One, has operated successfully in southern California since 1982; and a small experimental facility, rated at 0.75 MWe (gross) has been operated in New Mexico.[20] Small central receivers also have been built and operated overseas, but no solar pond has ever produced electric power in the United States. However, a 5 MWe unit is in operation in Israel and several ponds have been built and operated in the United States and elsewhere for applications other than the production of electricity. The solar pond *concept* however is considered to be well established and the successful commercial deployment of the technology is not expected to require any major technical breakthroughs.[21]

Parabolic Troughs and Dishes.—Unlike the ponds and central receivers, parabolic dishes and parabolic troughs already have been deployed in commercial-scale units. Indeed, commercial installations financed by private investors assisted by the Renewable Energy Tax Credits now are operating. Further demonstration and early commercial units are being planned over the next 5 years, though the extent to which the plans are realized depends heavily on Government tax policies or funding. As current units continue to operate, and as new units are added, the level of uncertainty and risk associated with the technologies will continue to drop.

At present, the **parabolic trough** is the most mature of the solar thermal electric technologies, with commercial units operating, under construction, and planned. Nearly 14 MWe (net) of privately financed capacity already is operating in southern California at the Solar Electric Generating System-I (SEGS-I); an additional 30 MWe (net), the Solar Electric Generating System-II (SEGS-II), now is being built. Additional capacity—150 MWe or more—may be added by early 1989 if the energy tax credits are extended in some form. Whatever the case, by 1990 more commercial experience will have been logged with this technology than any other solar thermal-electric alternative. The resultant low level of risk will constitute an important advantage for this technology. Other important advantages will be the technology's inherent storage capacity and the relatively wide variety of markets to which it could be applied—including industrial process-heat applications.

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[19] For a discussion of the solar pond's prospects in California, and of the limitations regarding sites, see Marshal F. Merriam, *Electricity Generation from Non-Convective Solar Ponds in California* (Berkeley, CA: Universitywide Energy Research Group, December 1983), UER-109.

[20] John T. Holmes, "The Solar Molten Salt Electric Experiment," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference*, Aug. 19-24, 1984. (San Francisco, CA: American Nuclear Society, 1984), Paper 849521.

[21] See: 1) Massachusetts Institute of Technology, *A State-of-the-Art Study of Nonconvective Solar Ponds for Power Generation* (Palo Alto, CA: Electric Power Research Institute, January 1985), EPRI AP-3842. 2) Edward I.H. Lin, *A Review of the Salt Gradient Solar Pond Technology*, op. cit., 1982.

But the troughs are saddled with several serious disadvantages which to some extent will constrain deployment. The technology's low efficiency is its most serious disadvantage. Another is the need by the SEGS units for a supplementary fuel such as oil or gas, and for considerable volumes of water. Finally, the system of conduits through which the heat-absorbing oil flows may develop problems or the oil itself may degrade at an excessive rate; these potential problems have not yet materialized at the SEGS-I installation, but further operating experience is required before long-term performance can be proven.

Two types of **parabolic dishes** may be deployed in the 1990s: the mounted-engine parabolic dish and the remote-engine parabolic dish. Each offers many design options. The primary advantages of the mounted-engine units are their high efficiencies, low water consumption, and ability to operate without supplemental fuel. The small size of the basic electricity-producing module also carries with it advantages. The system may be installed in many sizes, and multimodule installations may produce electric power long before the full installation is completed; individual modules or groups of modules may begin operating while others are being installed. Together these advantages provide the technology with considerable siting flexibility and potentially very short lead-times.

The largest disadvantage of the mounted-engine unit is the relatively high level of uncertainty about its performance, and the possibility that the engines may require an excessive amount of maintenance. Only three commercial-scale demonstration units—at about 25 kWe (net) each—had been deployed by May 1985, and few are scheduled to be deployed by 1990; no commercial installation yet exists, or is under construction. Other disadvantages include the lack of storage capacity and the inability to readily adapt the technology to cogeneration or nonelectric applications.

The remote-engine dishes, like the troughs, enjoy the advantage of being used at present in a commercial installation. A 3.6 MWe system, built by LaJet, Inc., now is operating in southern California. Also, like the troughs, the remote-engine technology may use as few as one or two engines; engine-related O&M costs therefore could be much lower than those of the mounted-engine parabolic dishes. The remote-engine technology in addition may be easily used for nonelectric applications. The LaJet design at present does not require a supplemental fuel.

But the remote engine technology is inefficient; much heat is lost as the heat transfer fluid is pumped from the collector field to the turbines. Also, the system has little storage capacity; electricity production therefore cannot be deferred for very long. And unlike the mounted-engine units, the remote-engine technology consumes sizable volumes of water.

Both dishes and troughs suffer from the same serious problem—they lack the cost and performance certainty which can only be gained through more commercial-size operations. This mitigates against private sector investment which is not in some manner accompanied by government support. At the current pace, it is uncertain whether the situation will change over the next 5 to 10 years.

Generally, capital costs will have to be reduced and performance improved if the technologies are to be deployed. To some extent this can be fostered by research oriented towards incremental improvements of the commercial-scale systems now operating. The most useful research would concentrate on low-cost, durable, and highly reflective reflector materials and inexpensive, long-lasting receivers and engines. But if the technologies are to be extensively deployed in the 1990s, the greatest overall need is to reduce uncertainty and thereby increase demand to the point where economies of scale can drive costs down.

By virtue of the fact that commercial-scale systems now are operating for troughs and dishes, the level of cost and performance uncertainty among the troughs and dishes will be considerably lower than the uncertainty associated with the central receiver and ponds in the 1990s. Between troughs and dishes, uncertainty will be lowest for troughs, highest for the mounted-engine dishes, and somewhere in between for remote-engine dish systems.

The mounted-engine dishes, in particular could benefit from greater deployment of commercial-scale units. A considerable reduction in uncertainty and greatly improved commercial prospects might result. Under such conditions, the mounted-engine parabolic dishes could eliminate the current lead enjoyed by parabolic troughs among the solar thermal technologies. If the engines perform well, the parabolic dish technology could well become the prevalent choice for solar thermal electricity production in the 1990s.

Typical Solar Thermal-Electric Installation for the 1990s.—The precise cost and performance of the solar thermal-electric systems in the 1990s will vary widely according to system design, location, overall market size, risk, and many other factors. No attempt here is made to fully discuss the cost, performance, and uncertainty of all the many solar thermal technologies. Rather, a single technology—the mounted-engine parabolic dish—is examined in fuller detail and used for reference purposes. The cost and performance numbers shown in appendix A, table A-2 for the mounted-engine parabolic dish installation in the 1990s represent reasonable estimates, but obviously should be viewed with caution.

By 1995, mounted-engine parabolic-dish plants might account for up to 200 MWe of installed capacity. The deployment level depends mostly on the extent of Government support over the next 5 to 10 years—primarily the Renewable Energy Tax Credit—and avoided cost rates.

The reference plant used in this analysis consists of 400 electricity producing modules, each independently tracking the Sun and producing electric power. The plant would have a gross capacity of 10.8 MWe and a net capacity of 10.2 MWe—the 0.6 MWe difference goes primarily to driving the tracking motors which keep the dish properly oriented toward the Sun during the day, and to cooling the engine. Other equipment required on the site include a central control unit, electric power subsystems, buildings, maintenance facilities, and other equipment.[22]

The amount of time required to build the plant should be very short, perhaps 2 years. The greatest uncertainty in this estimate lies with permitting and licensing. A large area of land—approximately 67 acres—would be required for the installation; the impacts of the development would be extensive. The most obvious impact would be visual, arising from the modules, roads, and transmission lines (see figure 4-7). Serious impacts on the soil and vegetation of the area could also occur. Installations in the 1990s probably would be concentrated in arid areas which have fragile soil and plant communities. Regulatory delays could result from concerns over all these impacts. Indeed, such problems reportedly have delayed the planned expansion of LaJet's Solarplant 1 facility in southern California (see box 7B in chapter 7).

The overall operating availability[23] of the installation could be quite high for several reasons. Routine maintenance could be conducted at night. Should a module not be working during the day, its incapacity would not impede the operation of other modules. As long as large numbers of unpredictable failures do not occur (as for example might happen after a severe and damaging storm), then high operating availabilities for the system as a whole can be maintained. The reference system used in this analysis is characterized by operating availabilities of 95 percent.

The expected plant lifetime is 30 years. Many of the components are relatively simple and durable. The power conversion unit (PCU) located at the focal point, which uses relatively unproven technology, is the component which creates the greatest uncertainty about plant lifetime. It is anticipated, however, that with a regular and perhaps expensive maintenance program, this uncertainty can be greatly reduced, although further development is needed to assure this.

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[22] Where Stirling engines are used, the other equipment includes systems which pressurize hydrogen for use in the Stirling engines.

[23] Operating availability here refers to the average percentage of modules capable of operating between sunrise and sunset. A 95 percent availability indicates that during the average day, 5 percent of the modules are not operating.

Wind Turbines

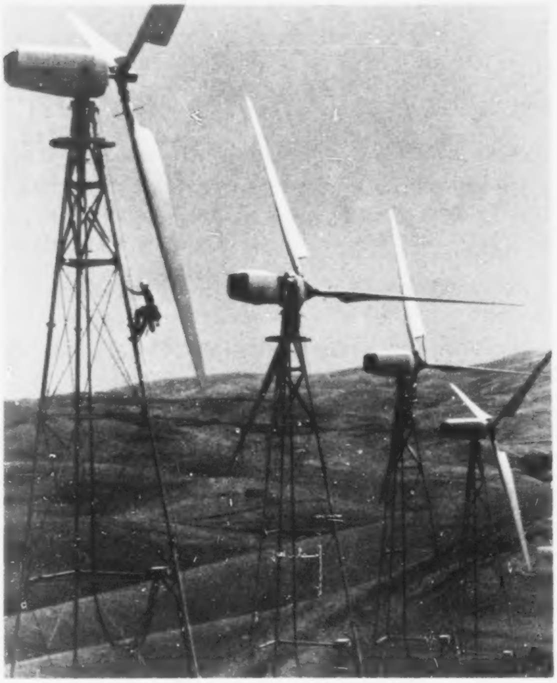
Introduction

A wind turbine converts wind into useful mechanical or electrical energy. Wind turbines may be classified according to the amount of electricity they generate under specified wind conditions. A small turbine generates up to 200 kWe, an intermediate-sized turbine can deliver from 100 to 1,000 kWe, and a large system may produce more than 1 MWe.

Since the early 1970s, the development of wind technologies for electric power production has followed two relatively distinct paths—one directed towards small turbines and the other towards the large machines. As the efforts relating to the large turbines bogged down with technical and economic problems, the small turbines—aided by State and Federal tax incentives—progressed very rapidly. In the early 1980s, wind turbines were extensively deployed, mostly in California, where 8,469 turbines were operating by the end of 1984. The total capacity of these units was approximately 550 MWe. Almost all were erected at windy locations, in clusters called "wind farms." By the end of 1984, many thousands of wind machines, with a total installed capacity of over 650 MWe, were producing electric power in the United States, and almost all were small turbines (see figure 4-12).

As operating experience accumulated with the small machines, both manufacturers and investors began to gravitate towards intermediate-sized machines. By the end of 1984, intermediate-sized machines were being deployed in small numbers. It is widely believed that if large numbers of wind turbines are to be manufactured and deployed in the 1990s, in free competition with other generating technologies, intermediate-sized machines probably will be favored over both small and large machines. Only the intermediate-sized machines promise sufficiently cheap power without imposing unacceptable risks (figure 4-13 illustrates a intermediate-sized vertical-axis wind turbine).

Figure 4-12.—Maintenance Crews Performing a Routine Inspection of a Small Wind Turbine



SOURCE: U.S. Windpower, Ed Linton, Photographer

While it appears that the total installed capacity of wind turbines in the United States may exceed 1,000 MWe by 1985, the rate of subsequent deployment is a matter of speculation. Given the short time within which a wind farm can be deployed and operated—from 1 to 2 years, excluding wind data gathering—growth under favorable circumstances could be extremely rapid. It is possible that the market potential for wind turbines could be as high as 21,000 MWe for the 1990-2000 period.[24]

The areas most favored for wind farms are those with good wind resources, heavy reliance on oil or gas, and with an expected need for additional generating capacity. They are located mostly in California, the Northeast, Texas, and Oklahoma. There are, however, less extensive but nevertheless promising opportunities elsewhere in the country, especially in parts of the Northwest, Michigan, and Kansas.[25] Most—though not all—

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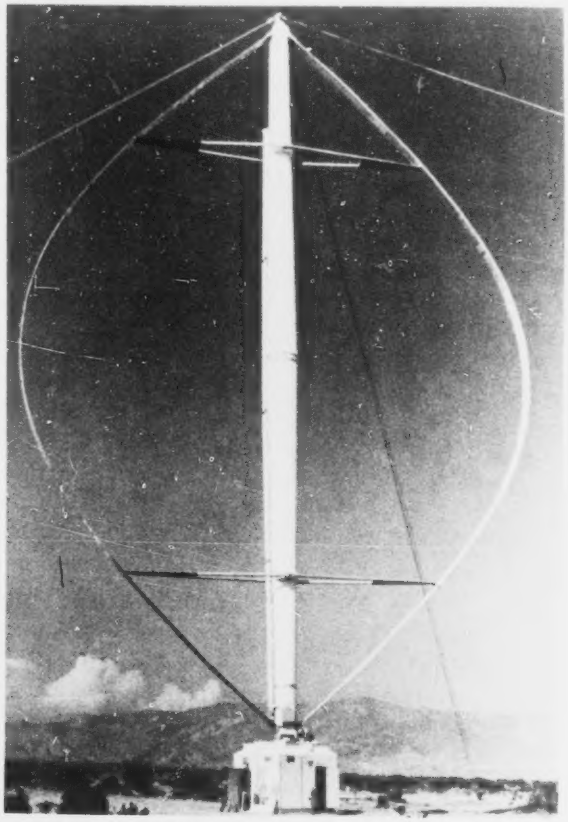
[24] Science Applications International Corp., *Early Market Potential for Utility Applications of Wind Turbines, Preliminary Draft* (Palo Alto, CA: Electric Power Research Institute, December 1984), EPRI Research Project 1976-1.

[25] Ibid.

Figure 4-13.—A 500 kW Vertical-Axis Wind Turbine



SOURCE: Southern California Edison Co.

turbines probably will continue to be installed in relatively large wind farms rather than individually or in small clusters. Figure 7-10 in chapter 7 indicates the distribution of the wind resource and the areas of the United States where wind development is most favored.

A Typical Wind Farm in the 1990s

The reference wind farm used in this analysis is summarized in appendix A, table A-4. A typical wind farm in the 1990s may consist of up to several hundred, 200 to 600 kWe wind turbines; the reference wind farm consists of 50 turbines with ratings of 400 kWe each. Installations could vary widely in the number of turbines deployed or in their exact ratings. But based on current projections, the important cost and performance characteristics would be common to the average facility considered by investors during that decade.

In addition to the turbines themselves, related equipment will be necessary at the site, including power conditioning equipment, system protection devices, security fencing, metering devices for measuring turbine output, wind measuring equipment for monitoring site conditions and equipment performance, control buildings, and a fabrication yard where equipment is stored and assembled.[26]

The turbines of the reference wind farm would be distributed over an area of anywhere from 300 to 2,000 acres, depending on the topography, prevailing wind direction, the shape and orientation of the property on which the farm is located, and the size of turbines being used. The turbines are spaced to avoid excessive interference with each other. Because installation and maintenance of the turbines requires vehicular access, at least one road leads to a wind farm and to each individual wind turbine (see figure 4-14) unless topography, surface characteristics, and regulations allow access without roads. Since the performance of the turbines and the cost of their power depends directly on wind exposure, all major obstructions such as trees would be removed.[27]

It is evident that the major environmental impacts of wind farms will result from their initial construction as well as from their high visibility, their extensive road networks, and from the activities of maintenance crews on the roads and around the turbines.[28] Among the other impacts, the severity of which may be assessed less readily but which nevertheless are considered potentially serious, are those associated with the noise created by turbine operation.

Concern over environmental impacts could seriously delay the deployment of wind turbines.

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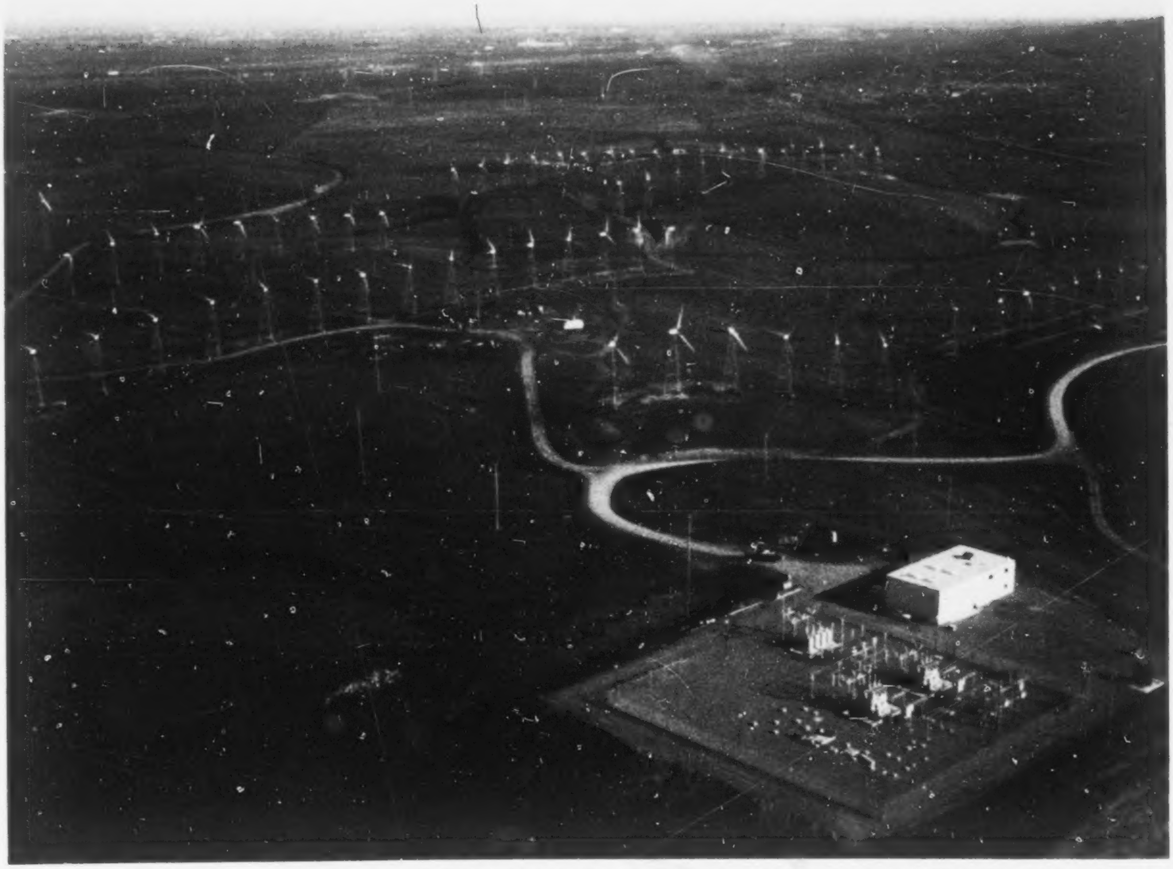
[26] Sam Sadler, et al., *Windy Land Owners' Guide* (Salem, OR: Oregon Department of Energy, 1984), p. 17.

[27] It should be noted that many prime wind sites, being exposed to frequent high velocity winds, are inhospitable environments for trees and therefore frequently are devoid of large, upright trees which could be considered serious obstructions.

[28] "Wind Farms, Timber Logging May Have Similar Environmental Impacts, Harvard's Turner Says," *Solar Intelligence Report*, Nov. 26, 1984, p. 375.

Figure 4-14.—Aerial View of a Wind Farm in the Altamont Pass in California



The control building and the substation are in the foreground. Note the extensive network of roads required for access to the turbines

SOURCE: U.S. Windpower, Ed Linton, Photographer

Serious delays could also result from unfamiliarity with the technology among regulators and the public; from the lack of regulations and procedures to expedite the handling of proposals affecting wind farms; and from the lack of adequate numbers of knowledgeable regulators, especially at the local level. Consequently, while the lead-time expected of a typical wind farm is 1 to 2 years, regulatory delays may stretch that period considerably.

Wind Farm Performance.—One measure of a wind farm's performance is its overall capacity factor, i.e., its actual output over a given period of time as a fraction of what it would produce were it to operate at full rated capacity during the same period of time. This indirectly reflects generator and rotor size, operating availability, the quality of the available wind resource, and the ability of the individual machines to fully exploit the resource. While data on these variables can be determined independently, actual capacity factors depend on interrelationships among all five under real operating conditions.

At present, the best means of estimating future capacity factors is by first examining current capacity factors. The trend has been towards higher capacity factors, especially as operating availability improves and as wind farms continue to be sited in windy areas. Under these favorable conditions, typical capacity factors between 20 and 35 percent are expected in the 1990s as the intermediate-sized turbine technology matures.

As the performance of wind turbines improves and is better understood, one especially large uncertainty still remains in estimating the annual outputs of turbines in the 1990s: the quality of the wind resource to which the turbines will be applied. Today's turbines are exploiting some of the best wind resources available. But new sites will be required, and the average quality of new sites probably will decline. High capacity factors will be progressively more difficult to maintain. At present, it is difficult to predict what wind regimes will characterize new sites exploited in the 1990s, because sufficiently detailed, site-specific wind data are not yet available in most instances. Information is accumulating, however, and it suggests that there remain considerable areas of land available with high-quality wind resources.

The lifetime of a wind farm is somewhat difficult to determine because individual turbines and even components of turbines can be replaced as needed; in a sense, the wind farm itself can outlive any of its individual components. Generally, the components of a wind farm in the 1990s will be designed to last 20 to 30 years, though some key components—such as the rotor—may fail and be replaced before that time.

Wind Farm Costs.—The average capital cost for wind turbines installed on California wind farms in 1984 was $1,860/kWe.[29] This capital cost however is heavily inflated as a result of the financing arrangements associated with current projects; one observer has estimated that in fact actual costs would be closer to $1,330/kWe if the financing mechanisms typical of utilities were used.[30]

The capital costs of the typical wind farm in the 1990s may range from $900 to $1,200/kWe. The reduced capital cost will result both from design improvements and from the more competitive market expected when the current favorable tax treatment is phased out. Termination or phaseout of the Federal and California State tax credits, for example, would very likely contribute to decreases in the capital costs.

Operating and maintenance costs for the wind farms of the 1990s could range between 6 and 14 mills/kWh. Available evidence indicates that costs for small turbines in 1984 ranged between 15 and 25 mills/kWh.[31] The high O&M costs which thus far have been incurred can be attributed to the fact that the first generations of machines, those deployed in the early 1980s, were plagued with mechanical problems. Changes in two areas will stimulate the reduced O&M costs: smaller numbers of turbines per kilowatthour generated and improved turbine design. Of central importance will be the maintenance of high operating availability.

An important cost associated with wind-generated electric power is the cost of access to the wind itself—if indeed access can be gained at any cost. The fee charged by the landowner typically is either in the form of a minimum rent, royalty payments, or some combination of the two.[32] Costs of access have increased substantially; landowners have already begun to appreciate the value of prime sites, particularly in California.[33] There, in 1984, annual land charges commonly amounted to 6 to 13 percent of gross revenues from the sale of the electricity over the lifetime of the contract negotiated between the developer and the landowner.[34]

The prospects for wind turbines in the 1990s would be enhanced by research and development. Among the most important R&D items are the need to better understand turbulence and predict its effects; to more readily and accurately model structural dynamics; to better predict noise problems; to accurately model wind farm cost and performance; and to develop, test, and characterize materials and components. The development of cheap, reliable, and accurate wind measurement instruments as well as better understanding and prediction of the wind's characteristics also are needed. Detailed and accurate assessments of the wind resource nationwide are necessary too.[35]

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[29] Conversation between Mike Batham, California Energy Commission, and OTA staff, Feb. 5, 1985. See also "California Adds 366 MWe of Wind Capacity: Size, Capacity Factor Up," *Solar Energy Intelligence Report*, Jan. 28, 1985, p. 30.

[30] Donald A. Bain, Wind Energy Specialist, Renewable Resources, Oregon Department of Energy, conversation with OTA staff, June 11, 1985.

[31] "Wind Turbine Operating Experience and Trends," *EPRI Journal*, November 1984, pp. 44-46.

[32] For a discussion of the determination of wind resource value and contractual arrangements see: Sam Sadler, et al., *Windy Land Owners' Guide*, op. cit., 1984.

[33] Teknekron Research, *Cost Estimates and Cost-Forecasting Methodologies for Selected Non-Conventional Electrical Generation Technologies* (Sacramento, CA: California Energy Commission, May 1982).

[34] Conversation between Mike Batham (California Energy Commission) and OTA staff, Nov. 30, 1984.

Geothermal Power

Introduction

Geothermal energy is heat stored beneath the Earth's surface. The U.S. Geological Survey (USGS) estimates as much as 1.2 million quads (a quad is 10^{15} Btu and is equal to 293 billion kWh) of accessible geothermal resources underlie 3.4 million acres of U.S. land, mostly within the western third of the country.[36] Only a small portion of the resource—approximately 3.8 percent of the total—occurs as hydrothermal resources—superheated water contained in a permeable rock formation and trapped below a layer of impermeable rock. The locations of major hydrothermal resources in the United States are provided in figure 7-9 of chapter 7. Steam (vapor-dominated resources) or water (liquid-dominated resources) convectively circulates towards the surface within the permeable rock formation. It is the hydrothermal resources which will continue to provide most of the geothermal electric development in the 1990s.

The temperature and quality of hydrothermal resources vary greatly. While a portion of the hydrothermal resource is very hot, most—roughly two-thirds of the identified resources—are in the moderate temperature range (150 to 250° F).[37] Geothermal development has in the past focused on the high-quality, vapor-dominated reservoirs, which are confined to limited areas of the United States.

The equipment required to exploit these high-quality resources is commercially available, and no major changes in the basic characteristic of the technology is likely during this century. There are available improved technologies, however, which not only could more economically exploit the high-quality resource, but also may economically tap the much more plentiful resources of lesser quality. Among these are single-flash, dual-flash, binary, and total flow systems.

The single-flash technology has been commercially deployed in the United States. Because this analysis focuses on technologies which are not already technologically mature, the single-flash technology will not be examined here. The total flow systems also will not be discussed, since they either require considerable further technical development, or will be applied only to a small number of high-quality sites in the United States. The total flow systems therefore are unlikely to constitute more than a small fraction of geothermal capacity additions in the 1990s. The dual-flash and binary systems will constitute the most important new technologies applied to the liquid-dominated geothermal resource in the 1990s, and, therefore, are the subject of this analysis.

Geothermal Power Technology

Before the resource is exploited to produced electric power, it must be located and assessed. This itself is a time-consuming, expensive process involving its own particular set of technologies and problems. Ultimately, resource assessment requires building roads, transporting drilling equipment to the site, constructing the rigs and drilling. Once the resource has been satisfactorily measured, the thermal energy next must be brought to the surface where it can be used. This too involves particular technologies and difficulties. An especially important technological hurdle which remains to be satisfactorily overcome is the development of cheap, reliable "downhole" pumps capable of moving the brine from the underground reservoir, and subsequently reinjecting it. While the brine is at the surface, a portion of its thermal energy is drawn off and used to produce electric power.

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[35] For a more detailed discussion of R&D needs and plans, see: 1) Solar Energy Research Institute, *Wind Industry R&D Planning Workshops: Summary Report* (Washington, DC: U.S. Department of Energy, July 1984. 2) State of Oregon, Department of Energy, *Final Report of the Wind Energy Task Force To the Oregon Alternate Energy Department Commission* (Salem, OR: Oregon Department of Energy, 1980), pp. 50-52. 3) U.S. Department of Energy, Wind Energy Technology Division, *Federal Wind Energy Program: Five Year Research Plan, 1985-1990 (Draft)* (Washington, DC: U.S. DOE, 1984).

[36] U.S. Geological Survey (USGS), *Assessment of Geothermal Resources of the United States—1978*, L.J.P. Muffler (ed.) (Washington, DC: U.S. Department of the Interior, 1979), USGS circular 790.

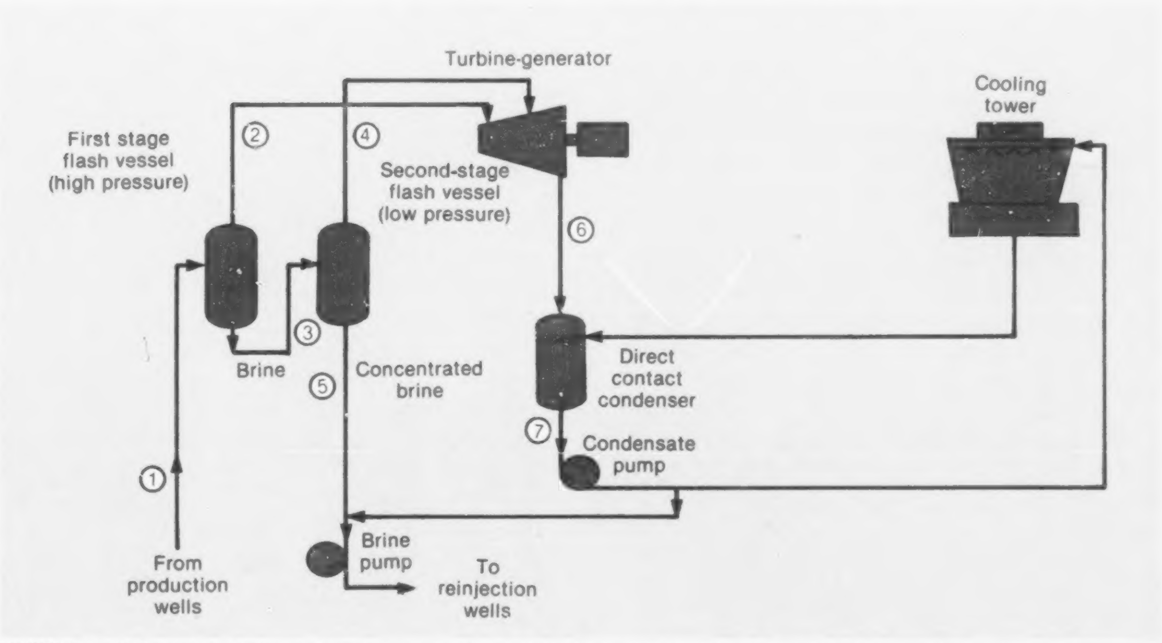
[37] M. Nathenson, "High-Temperature Geothermal Resources in Hydrothermal Convection Systems in the United States," *Proceedings of the Seventh Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI AP-3271, pp. 7-1 to 7-2.

Dual-Flash Systems.—Figure 4-15 illustrates the typical dual-flash unit. When liquid-dominated, high temperature brine—300 to several thousand pounds per square inch (psia) and 410 to 600 ° F—reaches the surface, a portion of the brine "flashes" into steam. First, a high pressure flash-tank processes the geothermal brine into saturated steam and spent brine. The steam enters one inlet of a dual-inlet turbine, while the unflashed brine goes on to a second, lower pressure flash-tank. The second-stage flash-tank produces further steam which is routed to the other inlets of the turbine. The remaining unflashed brine then is reinjected underground.

After exiting the turbines, the steam passes through a condenser, where it transfers its heat to a stream of cooling water. The cooling water is then routed to a cooling apparatus. Current designs use "wet cooling" devices in which the hot water is sprayed into the air and discharges its heat mostly through evaporation. The remaining water is recirculated to the condenser to repeat the cycle, along with "make-up" water required to compensate for evaporative losses. The condensed steam from the turbine is reinjected into the geothermal reservoir to help maintain reservoir pressure.

The make-up water requirements may be extremely large. The 50 MWe reference plant used in this analysis would require about 3 million gallons of make-up water daily, roughly six times the amount of water required by an atmospheric fluidized-bed combustor of comparable net generating capacity. The water requirements could be reduced with "dry-cooling" systems; but these are very expensive and reduce the plant's overall efficiency.

Figure 4-15.—Schematic of Dual-Flash Geothermal Powerplant



SOURCE: Peter D. Blair, et al., *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Wiley & Sons, 1982). Copyright 1982. Reprinted with permission of the publisher.

Alternatively, the water requirement could be greatly reduced by meeting it in part with the condensed steam from the condenser (instead of reinjecting it into the reservoir). This can only be done, however, to the degree allowed by contractual agreements and regulations. The field developer may require that all or part of the condensed steam be reinjected into the geothermal reservoir to maintain the quality of the resource. Or regulators may require some degree of reinjection in order to reduce subsidence problems.

The basic turbine, condenser, and cooling tower subsystem are similar to traditional steam powerplant designs, although there are significant differences. An important factor in the use of flash technology is the existence of noncondensable gases and/or entrained solids in the brine. These contaminants can cause scaling, corrosion, and erosion within the flash equipment, surface piping, and reinjection well casing. Development of highly saline resources has been slowed by these problems. Considerable research has been conducted to develop and demonstrate reliable removal technologies for these resources.

Although, operational dual-flash units abroad total 396 MW,[38] there is little commercial experience with these systems in the United States. None is now operating, and only one 47 MWe (net) dual-flash unit is under construction (see figure 4-16). Nevertheless, the dual-flash system will be used increasingly to exploit moderate to high temperature hydrothermal resources because it is more efficient than the single-flash system.[39]

Appendix A, table A-5 contains cost and performance estimates for dual-flash units in the 1990s. By the reference year 1995, dual-flash geothermal units will most likely range in size from 40 to 50 MWe. The expense of smaller units would be higher than would in most cases be justified by the advantages they might provide.[40] [41]

The units will require little land. Total acreage (including the geothermal wellhead, surface piping, and the powerplant) will not exceed 20 acres for a 50 MW plant. Directional drilling techniques[42] which tap various parts of a reservoir allow the wellhead and the plant to be confined to a small area.

The total lead-time required to bring a plant online typically should be 3 years, including licensing and permitting. Delays may be occasioned by concern over water requirements and various other environmental impacts. The latter could include atmospheric emissions, pollution or disruption of the watershed, and land impacts resulting from the construction and routine operation of the plant. This lead-time figure assumes that the geothermal resource has already been confirmed and developed, and that transmission facilities are available. Actual construction activity should take 1½ to 2 years. The first dual-flash unit at a resource could take as long as 5 years to establish, due to the initial permits and licenses that would be required.

Geothermal units are designed to operate on base load duty cycles. Operating availability is expected to run between 85 and 90 percent, and capacity factor should be between 75 and 80 percent.[43] The efficiency of geothermal technologies are measured in terms of resource utilization efficiency; i.e., net brine effectiveness—watt-hours per pound (Wh/lb) of steam. Typical net brine

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[38] R. Dipippo, "Worldwide Geothermal Power Development: 1984 Overview and Update," Altas Corp. (ed.), *Proceedings of the Eighth Annual Geothermal Conference and Workshop* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, pp. 6-1 through 6-15.

[39] The Electric Power Research Institute (personal communication between E. Hughes (EPRI) and OTA staff, Oct. 4, 1984) predicts that most of the planned flash plants at the Salton Sea and Brawley resources will use dual-flash technology.

[40] Based on:

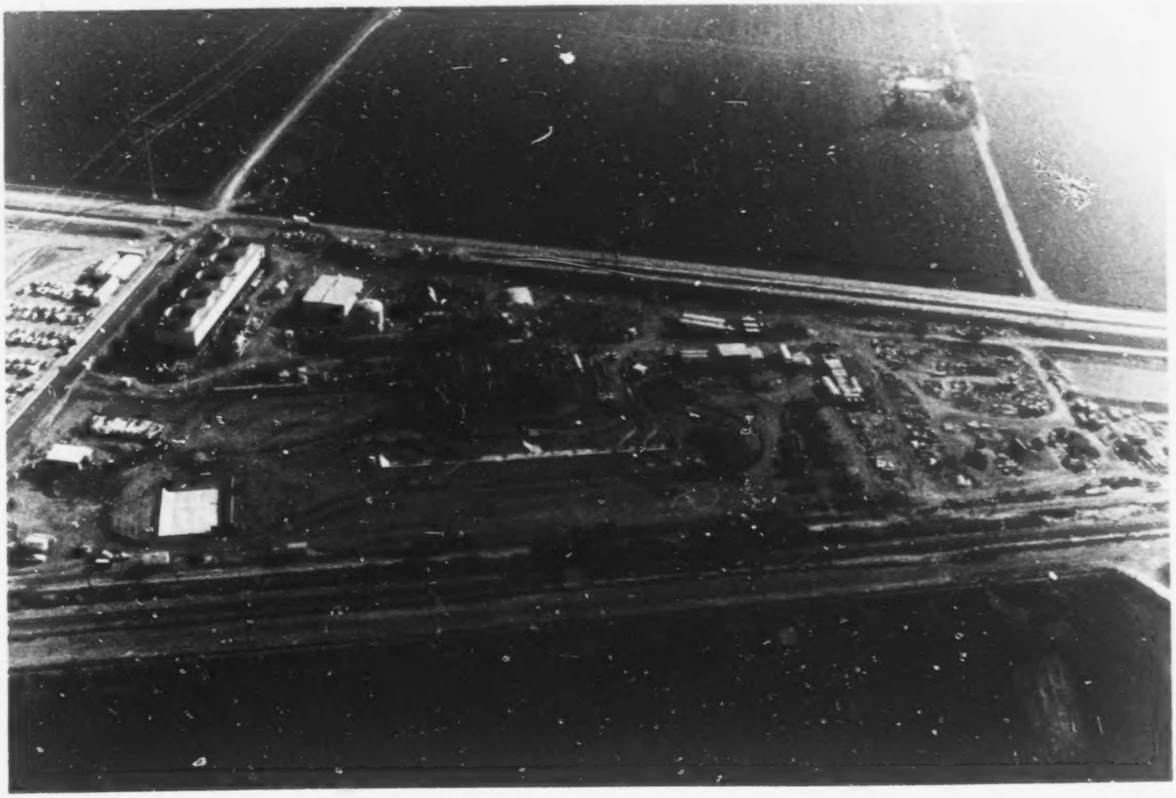
1. *Sourcebook on the Production of Electricity From Geothermal Energy*, J. Kestin (ed.) (Washington, DC: U.S. Department of Energy, March 1980), ch. 4, DOE/RA/4051-1.
2. Personal communication between Janos Laszlo (Pacific Gas & Electric) and OTA staff, Oct. 10, 1984.

[41] California Energy Commission, Systems Assessment Office, *Preliminary Energy Commission Staff Price Forecast for California Utilities* (Sacramento, CA: California Energy Commission, March 1984).

[42] Directional drilling involves a well bore that deviates from vertical. This form of drilling is used where the resource area underlies built-up areas, valuable cultivated land, and other difficult and expensive terrains.

[43] Estimate based on views expressed by participants at the Office of Technology Assessment's Workshop on Geothermal Power, Washington, DC, June 5, 1984.

Figure 4-16.—Aerial View of the Heber, CA, Dual-Flash Geothermal Installation



At the time the photo was taken, the plant was under construction.

SOURCE: Dravo Constructors, Inc.

effectiveness figures for dual-flash at 400° F resources will be 7 to 8 Wh/lb.[44] [45] At 600° F resources, net brine effectiveness may be as high as 25 Wh/lb.[46]

Typical capital costs for dual-flash units will probably run from $1,300 to $1,600/kWe. Actual costs will vary based on reservoir temperature, salinity, and the amount of noncondensable gases. The California Energy Commission[47] predicts that plants at highly saline resources could cost as much as $2,000/kWe.

Operation and maintenance costs will vary widely from resource to resource, ranging from 10 to 15 mills/kWh. Fuel (brine) costs are in large measure dependent on negotiations between the brine/steam supplier and the powerplant developer. Future brine fuel costs should be in the range of 50 to 70 mills/kWh.

Binary Cycle Systems.—In a binary plant (see figure 4-17), the brine is used to heat and vaporize a secondary working fluid with a lower boiling temperature than water. The secondary fluid then drives a turbogenerator to produce electricity. The use of a secondary working fluid complicates the design of the plant—it requires pumps to maintain brine and hydrocarbon pressure; special hydrocarbon turbines; heat exchangers; and

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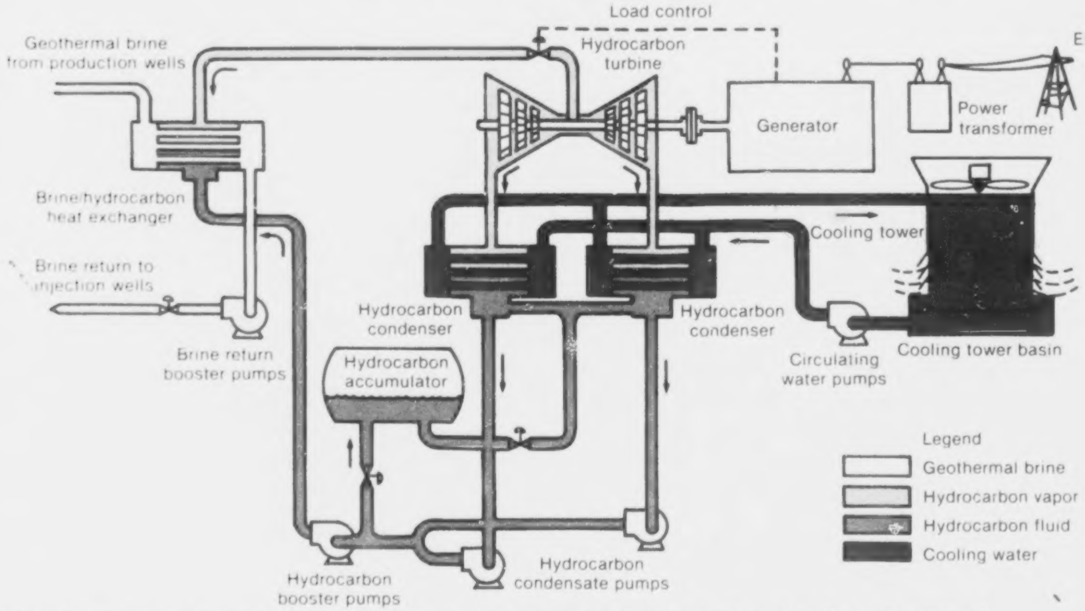
[44] T. Cassel, et al., *Geothermal Power Plant R&D, An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project* (Washington, DC: U.S. Department of Energy, 1983), DOE/CS/30674-2.

[45] Evan E. Hughes, "EPRI Geothermal Wellhead Projects," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, pp. 4-9 through 4-19

[46] Ibid.

[47] California Energy Commission, *Capital Cost of a Hydrothermal Flash Power Plant*, draft staff issue paper (Sacramento, CA: California Energy Commission, August 1984).

Figure 4-17.—Simplified Process Flow Diagram of Binary Cycle Technology


Load control
Geothermal brine from production wells
Hydrocarbon turbine
Electric grid
Generator
Power transformer
Brine/hydrocarbon heat exchanger
Cooling tower
Brine return to injection wells
Hydrocarbon condenser
Hydrocarbon condenser
Brine return booster pumps
Hydrocarbon accumulator
Circulating water pumps
Cooling tower basin
Legend
Geothermal brine
Hydrocarbon vapor
Hydrocarbon fluid
Cooling water
Hydrocarbon booster pumps
Hydrocarbon condensate pumps

SOURCE: San Diego Gas & Electric Co., *Heber Binary Project: Briefing Document* (San Diego, CA: San Diego Gas & Electric Co., 1984), p. 5.

surface condensers (instead of direct contact condensers).

The major advantages of binary cycles relate to efficiency, modularity, and environmental considerations. First, working fluids in binary cycles can have thermodynamic characteristics superior to steam, resulting in a more efficient cycle over the same temperature difference.[48] Second, binary cycles operate efficiently at a wide range of plant sizes. Especially attractive are small plants which, in addition to encouraging short leadtimes, have many other important advantages as well. Third, since the brine is kept under pressure and reinjected after leaving the heat exchanger, air pollution, e.g., hydrogen sulfide, from binary plants can be tightly controlled. There are also several other cost and efficiency advantages of binary technology over the dual-flash systems. Nevertheless, the dual-loop design of binary cycles is more complex and costly than a flash design.

Binary cycle technology is in developmental stages with few large operational generating units. By the end of 1985, one large 45 MWe (net) binary plant will have been installed near Heber, California (see figure 4-18); in addition, small binary plants, with a total capacity of about 30 MWe, will be operating.[49] This will account for most of the binary capacity installed worldwide. Development is expected to proceed, and extensive commercial deployment is feasible in the 1990s.

The expected cost and performance of binary geothermal plants in the 1990s are summarized in appendix A, table A-5. Data is provided for two reference plants, a large plant of about 50 MWe (net) and a small plant of about 7 MWe (net). The large plant could require up to 20 acres of land for the powerplant and for the maze of piping required for both the brine and the working fluid. The small unit might occupy 3 acres or less.[50] As with the the dual-flash technology, very large

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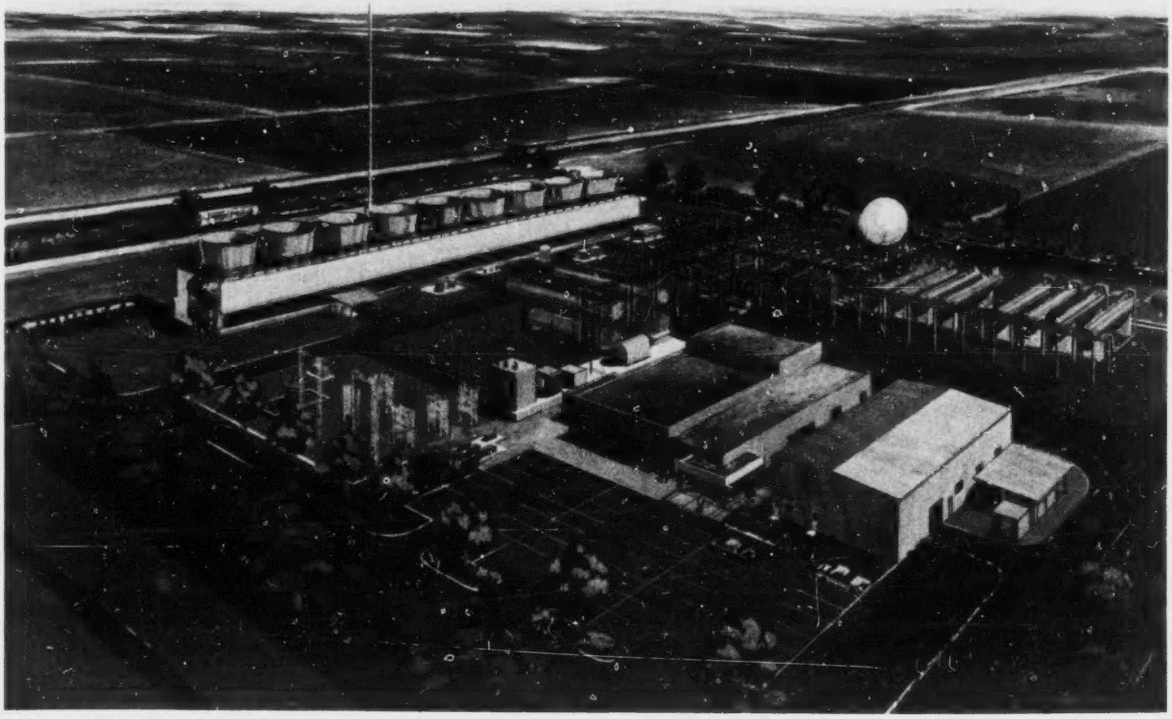
[48] P. Blair, et al., *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Wiley & Sons, 1982).

[49] Ronald DiPippo, "Worldwide Geothermal Power Development: 1984 Overview and Update," op. cit., 1984.

[50] Personal communication between H. Ram (Ormat, Inc.) and OTA staff, Oct. 6, 1984.

Figure 4-18.—Artist's Conception of the Heber, CA, Binary Geothermal Installation



SOURCE: San Diego Gas & Electric Co

volumes of cooling water are required; indeed, the water requirements are even larger than the dual-flash units. The large plant would require over 4 million gallons each day. The smaller plant would need about 0.6 million gallons per day.

Small plants of about 5 to 10 MWe (net) can be erected and operating on a site in only 100 days. But prior licensing, permitting, and other preconstruction activities could extend the lead-time to 1 year.[51] Construction of larger binary units should take only 1½ to 2 years.[52] But here too, overall lead-times will be longer because of preconstruction activities, including licensing and permitting. About 5 years total might be required for the first plant at a resource, and 3 years might be necessary for subsequent additions. With both small and large plants, problems about water requirements and environmental impacts could seriously extend the licensing and permitting process.

Binary cycle plants are designed to operate continually in base load operation. Availability is expected to be between 85 and 90 percent, and capacity factors are likely to be in the 75 to 80 percent range. Binary plants should last at least 30 years.

The net brine effectiveness of binary cycle plants may vary between 7 and 12 Wh/lb of steam at a 400° F resource. Advanced binary technology in the larger sizes should increase present effectiveness values at Heber from 9.5 to 12 Wh/

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[51] Wood & Associates, a geothermal energy developer, has had permitting problems at the county, State, and Federal level at its site near Mammoth Lakes, CA.

[52] San Diego Gas & Electric also had problems getting their large binary plant through the permitting process. Its problems, however, were encountered during the California Public Utilities Commission's plant approval process.

lb,[53] while smaller modular plants will probably have a net brine effectiveness between 7 and 9 Wh/lb.[54]

Capital costs for large binary cycle geothermal plants could range from $1,500 to $1,800/kWe in the 1990s. The smaller, wellhead units will probably vary from $1,500 to $2,000/kWe. The lower part of this range should be associated with the truly modular designs, which require little onsite construction, while the semimodular wellhead units (those which require a greater amount of onsite fabrication) should tend towards the higher part of this range. The capital cost estimates for both large and small units are lower than those which are expected to characterize early demonstration units.

Operation and maintenance costs are expected to range between 10 and 15 mills/kWh for all except the modular units. The simpler and smaller units should show O&M costs of 4 to 6 mills/kWh. Fuel, i.e., brine, costs will vary significantly by resource and resource developer. A range of 20 to 70 mills/kWh is most likely.

Fuel Cells

Introduction

A fuel cell produces electricity by an electrochemical reaction between hydrogen, supplied by a hydrocarbon fuel, and oxygen. Neither combustion nor moving parts are required in the conversion process. Fuel cell powerplants are expected to generate electrical power very efficiently and with modest environmental impacts relative to those of combustion technologies. Fuel cell installations may be capable of being deployed economically in a wide variety of sizes, ranging from small cogeneration units to large central power stations. In addition, they can be installed in many locations, including areas where both available space and water are limited. Among the other advantages which have attracted strong interest with investors are:

- responsiveness to changes in desired output,
- short lead-times,
- easily recovered waste heat,
- fuel flexibility,
- off-site manufacturing, and
- ability to operate unattended.

Most of the commercial demonstration plants crucial to the future of the fuel cell will *not* begin operations until the late 1980s, though by May 1985, a 4.5 MWe demonstration plant was operating successfully in Japan and thirty-eight 40-kWe demonstration units were operating in the United States.[55] Should the performance of the demonstration units be very good, limited quantities of commercial fuel cells may be produced at the earliest at the end of this decade or the beginning of the next.[56] [57]

The level of deployment depends heavily on the success of the demonstration units; the period of time deemed necessary to generate investor confidence; and the willingness of the vendors to share the risk and cost of the early units. The perceptions and decisions of investors, vendors and buyers cannot be accurately and confidently predicted, but current evidence suggests that the early 1990s may see the beginnings of fuel-cell mass production and the first commercial applications. As much as 1,200 MWe of fuel cell powerplant capacity may be operating by 1995.

The low production levels will drive installed capital costs down somewhat, but they will remain far above possible costs in a mature market. High-volume mass production is unlikely to occur until a sizable market is anticipated—in the mid-1990s at the earliest. Such a market may develop as investors observe the continued operation of the demonstration units and the initial operation of the early commercial installations.

Most important to the prospective investors will be operating and maintenance costs, economic life, and reliability. In particular, investors are likely to be sensitive to the rate at which fuel cell performance degrades over time under various operating conditions as well as the cost and difficulty of replacing cells when their performance becomes unacceptable. There is uncertainty among investors over these two points, both of which are crucial to the fuel cell's ultimate commercial prospects. Should problems be encountered in either area in early commercial prototypes, commercial deployment will be delayed. If powerplant operation is favorable, subsequent market growth in the latter half of the 1990s could be very rapid.

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[53] T. Cassel, et al., *Geothermal Power Plant R&D, An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project*, op. cit., 1983.

[54] Personal communication between H. Ram (Ormat, Inc.) and OTA staff, Oct. 6, 1984.

[55] J.W. Staniunas, et al., United Technologies Corp., *Follow-On 40-kWe Field Test Support, Annual Report (July 1983-June 1984)* (Chicago, IL: Gas Research Institute, 1984), FCR-6494, GRI-84/0131.

[56] Peter Hunt, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells* (Alexandria, VA: Peter Hunt Associates, 1984), OTA contractor report OTA US-84-11.

[57] Battelle, Columbus Division, *Final Report on Alternative Generation Technologies* (Columbus, OH: Battelle, 1983), vols. I and II, pp. 13-11.

Basic Description

The typical fuel cell powerplant will consist of three highly integrated major components: the fuel processor, the fuel cell power section, and the power conditioner. The fuel processor extracts hydrogen from the fuel which can be any hydrogen-bearing fuel, though most installations in the 1990s are expected to employ natural gas.

The hydrogen is then fed into the fuel-cell power section, the heart of which are "stacks" of individual fuel cells. The operation of a single fuel cell is schematically illustrated in figure 4-19. The cells are joined in series (the stacks), which, in turn, are combined to form a powerplant. There are several types of fuel cells being developed. These are categorized according to the type of electrolyte—the medium in which the electrochemical reaction occurs—they use. The first-generation fuel cells use phosphoric-acid as the electrolyte. These cells are the most developed and are likely to account for most of the fuel cells deployed in the 1990s.

Other less mature, fuel cell designs which employ alternative electrolytes promise superior performance; molten carbonate cells are the closest to commercial application, but are not expected to be commercially deployed until the late 1990s at the earliest. They therefore are not likely to account for an important share of fuel cell powerplants installed in the 1990s.[58] [59]

The electrical power which flows from the fuel cell stacks is direct current (DC). With some voltage regulation, this DC power can be used if the load is capable of operating with direct current. Otherwise, a power conditioner is required to transform the direct current into alternating current. This allows it to be fed into the electrical grid and to be used by alternating-current electrical motors.

The components of the fuel cell plant are tightly integrated to reduce energy losses through the proper management of fuel, water, and heat (see figure 4-20). Various parts of the plant benefit from the byproducts of other parts of the installation. Further efficiency gains result when byproduct heat from different parts of the plant are tapped for external use. The fullest exploitation of the fuel cell's heat may yield total energy efficiencies of up to 85 percent for the entire plant. The heat can be used for domestic hot water, for space heating, or to provide low-level process heat for industrial uses.

Typical Fuel Cell Powerplants for the 1990s

The expected cost and performance of typical fuel-cell powerplants for the reference year 1995 are summarized in appendix A, table A-7. Because no complete powerplants identical to those which might be deployed at that time exist today, these values remain estimates.

The units deployed in the 1990s probably will be built around two sizes of fuel cell stacks. The larger stacks are likely to be capable of generating approximately 250 to 700 kWe (gross, DC) each and the smaller stacks about 200 to 250 kWe (gross, DC) each. The plants built around the small stacks will be installed mostly in large multifamily dwellings, commercial buildings, and in light industries; most will probably be used to cogenerate both electricity and useful heat. The typical system would consist of at least two complete self-contained modules (see figure 4-21), each of which might produce about 200 kWe (net, AC).

Plants using the larger fuel cell stacks most likely will be deployed primarily by electric utilities, and by industries which would use them in cogeneration applications. Installation capacities probably

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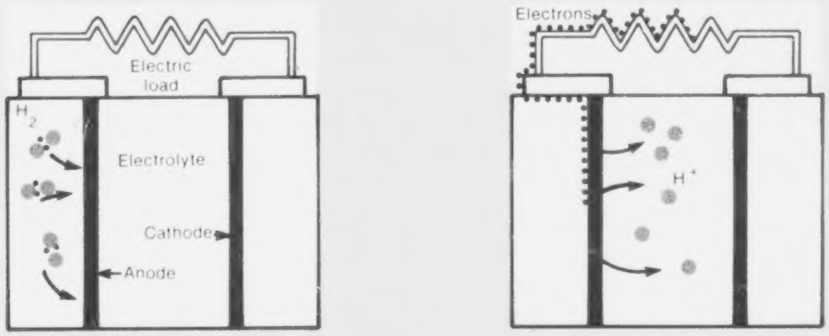
[58] Peter Hunt, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells*, op. cit., 1984.

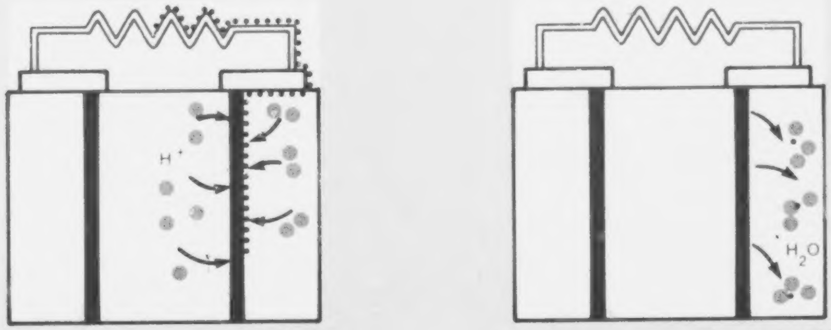
[59] U.S. Congress, Office of Technology Assessment Workshop on Fuel Cells, Washington, DC, June 5, 1984.

Figure 4-19.—Schematic Representation of How a Fuel Cell Works



1. Hydrogen gas flows over negative electrode (anode).

2. Electrons split away from hydrogen and flow through anode to external electric load.



3. Hydrogen ions move through electrolyte to cathode. Electrons stream into cathode from load. Cathode is bathed with oxygen.

4. Hydrogen, electrons, and oxygen combine to form water (steam).

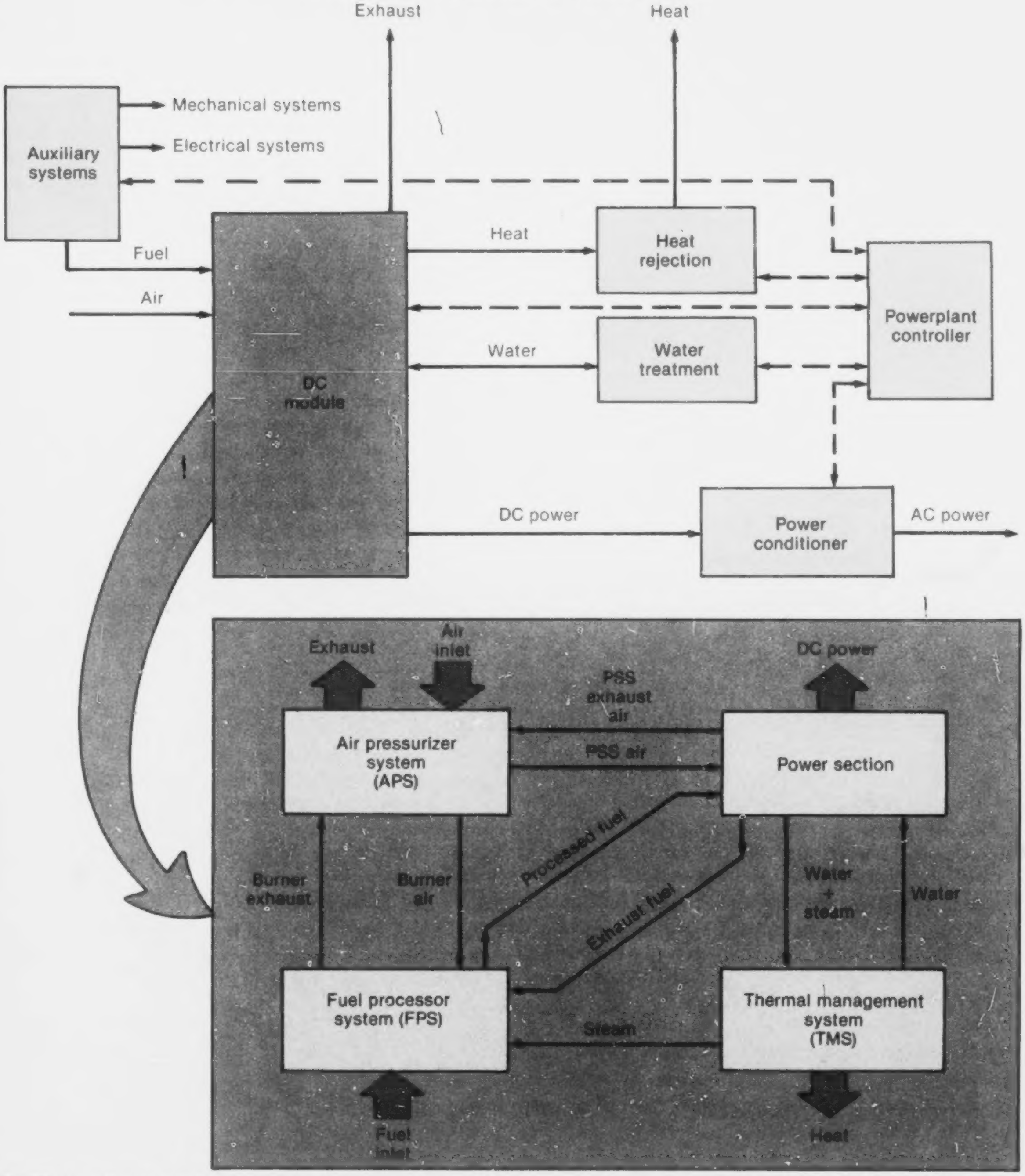
SOURCE: Ernest Raia, "Fuel Cells Spark Utilities' Interest," *High Technology*, December 1984.

will range from several megawatts on up. The reference installation used in this analysis is 11 MWe (net). Many of the major components would be fabricated in factories and shipped to the site on pallets.

The lead-time of a small fuel cell powerplants should be about 2 years. These units are relatively small, unobtrusive, and quickly and easily erected. Modules subsequently added at the same site could require as little as a few months. Regulatory delays are unlikely because of relatively minor siting and environmental considerations.

Installations utilizing the larger stacks, however, may encounter more serious regulatory problems. Unlike the approximately 480 to 600 square feet required by an installation of two, 200 kWe units, an 11 MWe installation would occupy about 0.5 to 1.2 acres of land (see figure 4-22). Because the plants frequently may be located in the midst of populated areas, the opportunity for regulatory conflicts with these larger plants is considerably greater. Partly offsetting these factors, though, are the environmental advantages associated with fuel cell powerplants. Hence, a lead-time of 3 to 5 years is anticipated with the larger units, considerably longer than the small plant's lead-time, but also much shorter than that of most conventional powerplants. As with the smaller fuel cell installations, capacity subsequently added to an already existing fuel cell plant should require considerably shorter lead-times.

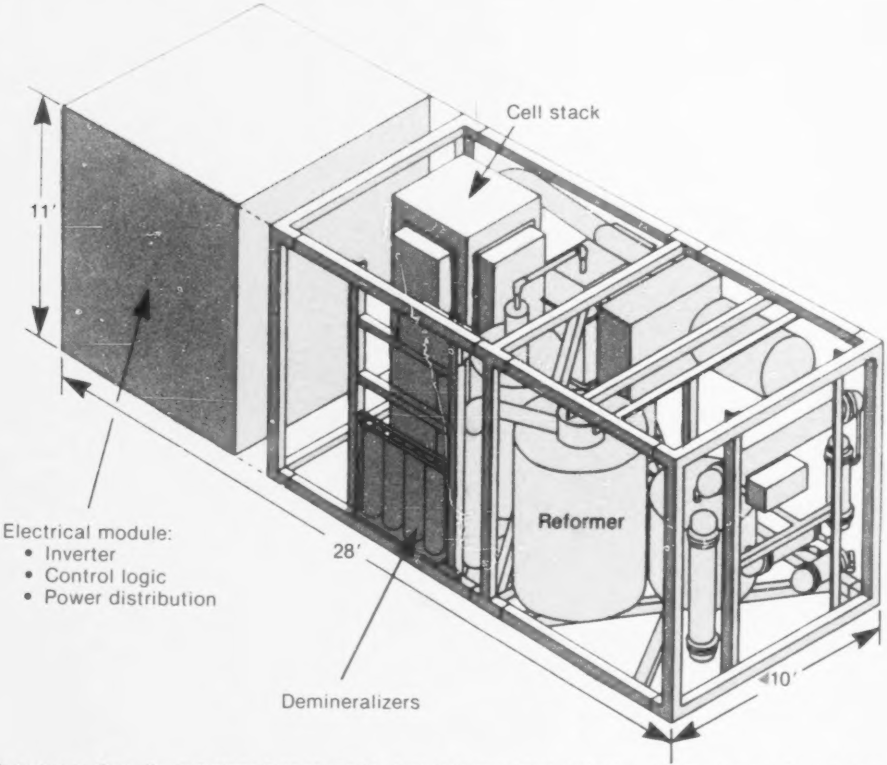
Figure 4-20.—Simplified Block Diagram of an 11-MWe Fuel Cell Plant. Detail of the DC Module is Provided Below.


Exhaust
Heat
Auxiliary systems
Mechanical systems
Electrical systems
Fuel
Air
Heat
Heat rejection
Powerplant controller
Water
Water treatment
DC module
DC power
Power conditioner
AC power
Exhaust
Air inlet
DC power
PSS exhaust air
PSS air
Air pressurizer system (APS)
Power section
Burner exhaust
Burner air
Processed fuel
Exhaust fuel
Water + steam
Water
Fuel processor system (FPS)
Steam
Thermal management system (TMS)
Fuel inlet
Heat

SOURCE: United Technologies Corp., *Description of a Generic 11-MW Fuel Cell Powər Plant for Utility Applications* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EM-3161.

Figure 4-21.—Design for a 200 kWe Fuel Cell Module

While basically similar to units which might be deployed in the 1990s, this design differs in several important details



SOURCE: United Technologies Corp., Power Systems Division, *On-Site Fuel Cell Power Plant Technology and Development Program Annual Report* (January-December 1983) (Chicago, IL: Gas Research Institute, 1984), FCR-6243 GRI-84/109.

The operating availability of large fuel cell powerplants may range between 80 and 90 percent. Availability is heavily dependent on the quality of design—its simplicity, the extent to which it has redundant components, the number of parts, and their reliability—and on the availability of spare parts and repair people when they are needed.

The fuel cell can be applied to any duty cycle. The fuel cell has excellent load following capabilities and high efficiency over a wide variety of operating levels.

The fuel cell powerplant's lifetime is assumed to be approximately 20 to 30 years with periodic overhaul of the fuel cell stacks and other components. Over time, the powerplant's efficiency drops. The timing of overhauls will vary; schedules will be a function of the performance reduction over time and of other factors such as the cost of fuel.[60] In some cases the stacks must periodically be removed and replaced with new ones. The old unit then is shipped back to a manufacturing plant where its catalyst (in the fuel processing section) and perhaps other components are removed, processed, and recycled. While the overhaul schedule and costs are uncertain, it is assumed here that all stacks are replaced after the equivalent of 40,000 hours of operation at full capacity.

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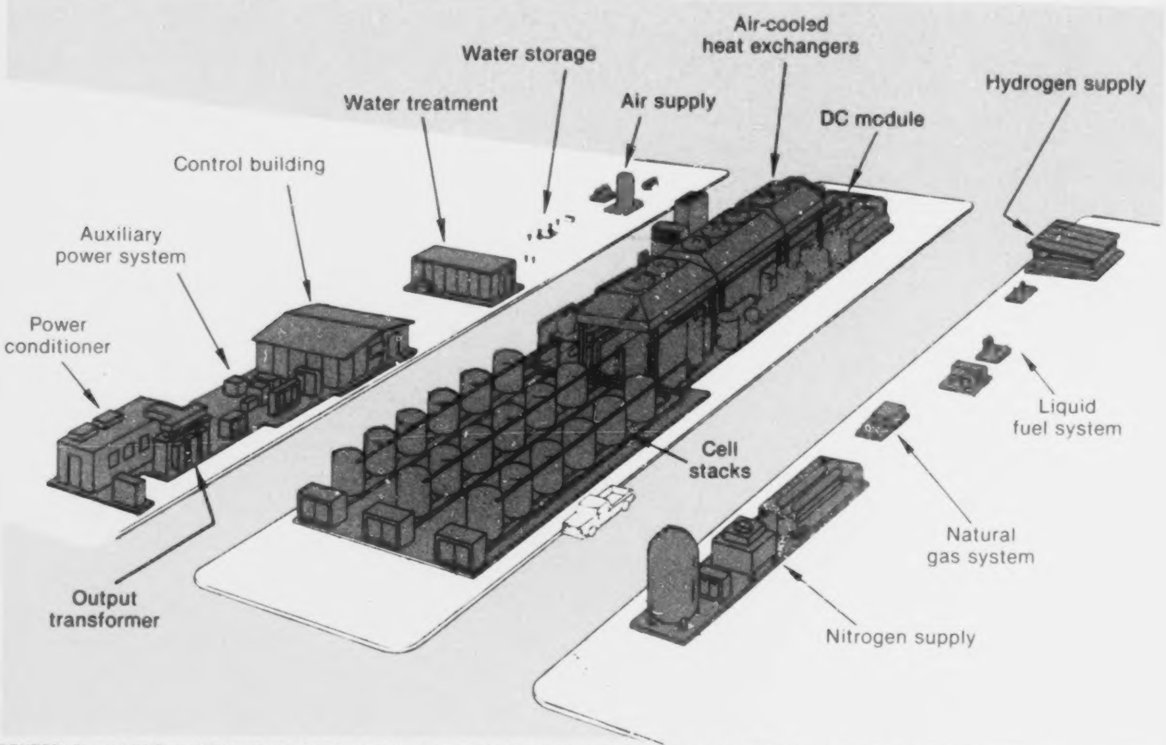
[60] J.R. Lance, et al., Westinghouse Electric Corp., "Economics and Performance of Utility Fuel Cell Power Plants," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849133.

Figure 4-22.—Typical Arrangement of 11 MWe Fuel Cell Powerplant


Air-cooled heat exchangers
Water storage
Hydrogen supply
Water treatment
Air supply
DC module
Control building
Auxiliary power system
Power conditioner
Liquid fuel system
Cell stacks
Natural gas system
Output transformer
Nitrogen supply

SOURCE: Burns & McDonnell Engineering Co., *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EM-3512.

Efficiencies[61] for large fuel cell plants are expected to be between 40 and 44 percent. Small plants may have efficiencies of approximately 36 to 40 percent. The estimated efficiencies are those which might characterize a plant over its lifetime; efficiencies of new stacks could be higher while those of older stacks might be below that level.

The installed capital costs of fuel cell power plants are expected to range from $700 to $3,000/kWe for large units to $950 to $3,000/kWe for small plants; expected values for 1995 are $1,430/kWe and $2,240/kWe respectively. The low numbers can be expected where units are commercially produced in large numbers; the high numbers are representative of prototype units and include nonrecurring costs. By far the largest expense is the fuel-cell power section itself; it is expected to account for about 40 percent of the costs of a mature 11 MWe plant.[62] The largest decrease in capital costs over the next decade will come from increases in the levels of fuel-cell production. However, technical improvements in the fuel-cell plant itself may substantially reduce costs as well. Already, over the past several years, design changes have reduced costs by an appreciable amount.

Operating and maintenance costs may range between 4.3 and 13.9 mills/kWh. The biggest element in O&M costs is the cost of periodically replacing cells stacks. For specific applications, the actual O&M costs will depend on the overhaul period for the cell stacks and the material and labor costs for each overhaul.

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[61] Based on higher heating-value.

[62] United Technologies Power Systems, *Study on Phosphoric Acid Fuel Cells Using Coal-Derived Fuels* (South Windsor, CT: United Technologies Power Systems, Apr. 27, 1981), prepared for Tennessee Valley Authority, contract No. TV-52900A, FCR-2948.

Fuel costs are expected to be approximately 27 to 33 mills/kWh, accounting for the major portion of electricity costs from fuel cells. Fuel costs also constitute the fuel cell's greatest advantage over some of its competitors such as the gas turbine, due to the fuel cell's high efficiency which yields substantially lower per kilowatt-hour fuel costs. Major variations in fuel costs per kilowatt-hour will result primarily from fluctuations in fuel prices. Fuel cell efficiency variations, due to technical improvements or maintenance practices (especially stack reloading schedules), also would be reflected in different fuel costs. In the longer term, post-2000, it is expected that natural gas will have to be replaced with more abundant fuels. Primary candidates are synthetic fuels—especially methanol—from coal and biomass.

Stacks are of central importance in determining capital, O&M, and fuel costs. The development and extended demonstration of cheap (per kWe) and reliable stacks which can operate at high efficiencies for extended periods are critical to the success of the technology. Technological improvements which could be especially important in this regard are the development of inexpensive, corrosion-resistant cell structural materials and less expensive and more effective catalysts to operate at higher pressures and temperatures, and improved automated fabrication and handling processes for large area cells. Also important is the development of cheap, reliable and efficient small-scale reformers (fuel processing units) and the improvement of various other standard components.

Combustion Technologies

Integrated Gasification/Combined-Cycle Powerplants

Introduction.—A coal gasification/combined-cycle powerplant centers around two elements. First is a gasification plant which converts a fuel into a combustible gas; other equipment purifies the gas. Second is a combined-cycle powerplant in which the gas fuels a combustion turbine whose hot exhaust gases are used to generate steam which drives a steam turbine. While the gasification system can be quite separate and distinct from the combined-cycle system, they *can* be integrated so that some of the heat discharged in the gasification sequence is exploited in the combined-cycle system, and a portion of the heat discharged by the combined-cycle unit may be routed back for use in the gasification plant (see figure 4-23). This section focuses on such integrated units, commonly referred to as IGCCs.

The primary attractions of the IGCC are its fuel efficiency and its low sulfur dioxide, carbon monoxide, nitrogen oxide, and particulate emissions. The high efficiency allows for fuel savings and hence reduced operating costs. The potential for very low emissions makes the technology particularly attractive for using coal to generate electric power. Another advantage allowed by the IGCC is "phased construction." Some parts of the plant may be installed and operated before the rest of the plant is completed;[63] this can be financially advantageous and is considered a major selling point for the technology. The IGCC also may be very reliable. In addition, the technology requires less land and water than a conventional scrubber-equipped, pulverized coal boiler powerplant. Furthermore, its solid wastes are less voluminous and less difficult to handle than those of its scrubber-equipped competitor and of the atmospheric fluidized-bed combustor (AFBC). Current estimates are that solid wastes from an IGCC will be 40 percent of a pulverized coal boiler and 25 percent of an AFBC of comparable size.

The evidence suggests that the IGCC offers a favorable combination of cost and performance when compared to its competitors (see also chapter 7). Nevertheless, a combination of two factors—lead-times and risk—may mitigate against its extensive deployment within the 1990s. Because of its modular nature and positive environmental features, potentially the IGCC has lead-times of no more than 5 to 6 years. It is likely, however, that the first plants, at least, will require longer times—up to 10 years—because of regulatory delays, construction problems and operational difficulties associated with any new, complex technology. It may take a number of

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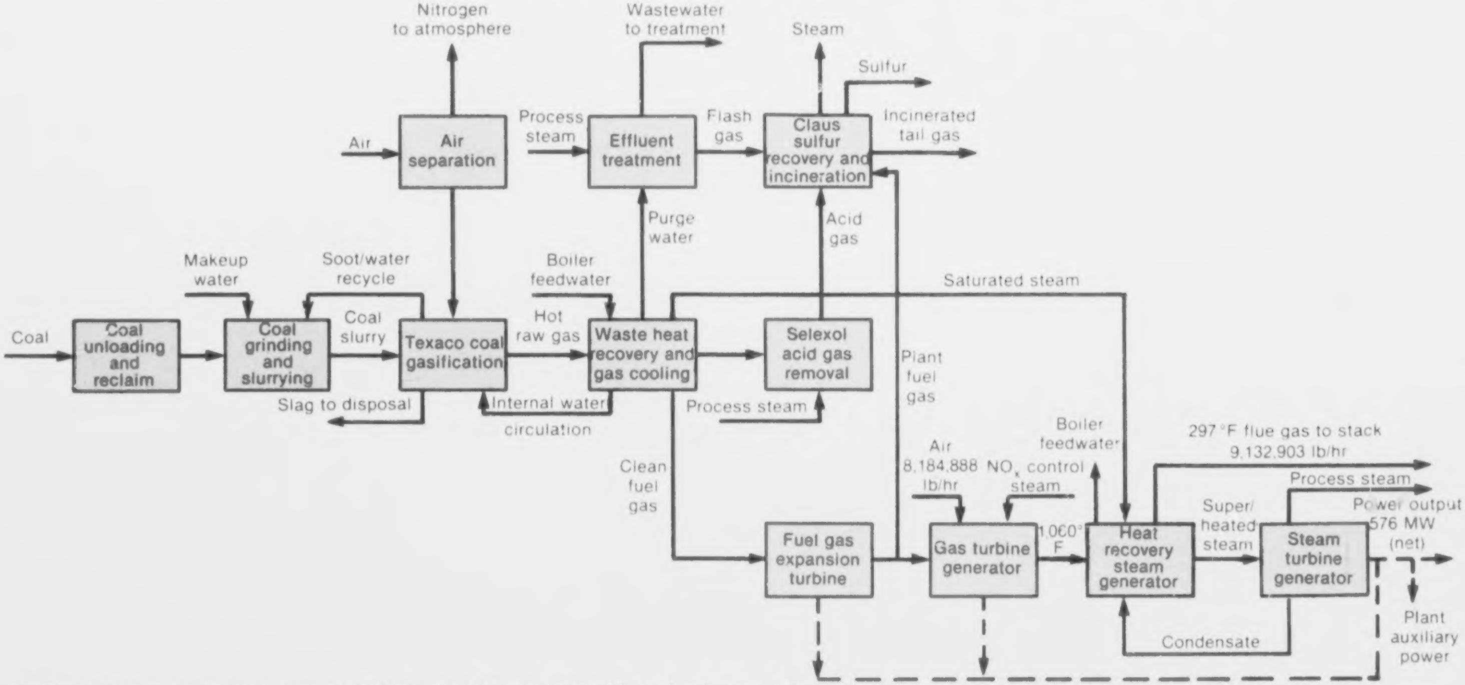
[63] For example, the gas-turbine/generator sets may be installed before the gasifiers and operated off of natural gas. When the gasifiers are completed, the synthetic gas then may be used instead.

Figure 4-23.—Simplified IGCC Flow Diagram of Texaco Gasifier

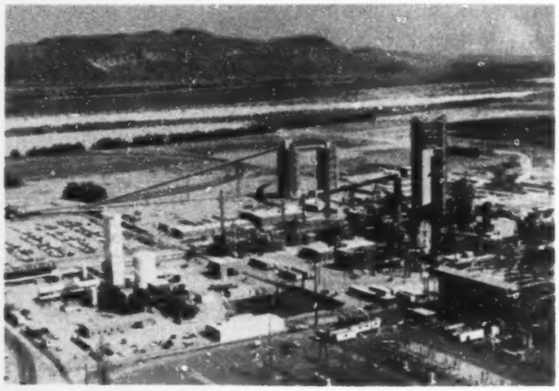

Coal
Coal unloading and reclaim
Makeup water
Coal grinding and slurrying
Soot/water recycle
Coal slurry
Slag to disposal
Air
Air separation
Nitrogen to atmosphere
Texaco coal gasification
Internal water circulation
Hot raw gas
Boiler feedwater
Waste heat recovery and gas cooling
Process steam
Effluent treatment
Wastewater to treatment
Purge water
Flash gas
Claus sulfur recovery and incineration
Steam
Sulfur
Incinerated tail gas
Acid gas
Selexol acid gas removal
Process steam
Saturated steam
Plant fuel gas
Clean fuel gas
Fuel gas expansion turbine
Air 8,184,888 lb/hr
NO$_x$ control steam
Gas turbine generator
1,060° F
Boiler feedwater
Heat recovery steam generator
297 °F flue gas to stack 9,132,903 lb/hr
Super/heated steam
Process steam
Steam turbine generator
Power output 576 MW (net)
Condensate
Plant auxiliary power

SOURCE: Argonne National Laboratory and Bechtel Group, Inc., *Design of Advanced Fossil Fuel Systems: A Study of Three Developing Technologies for Coal Fired, Base-Load Electric Power Generation* (Argonne, IL: Argonne National Laboratory, 1983).

commercial plants before the short lead-time potential of the IGCC is met, unless strong steps are taken to work closely with regulators and to assure quality construction for these initial plants. Such steps may be facilitated if the early plants are in the 200 to 300 MWe range rather than the current design target of 500 MWe. Should the longer lead-times be the case, projects must be initiated no later than the end of 1991 and perhaps as early as the end of 1989 if they are to be completed within the 1990s.

In addition to these possible longer lead-times, limited experience with IGCC demonstration plants may also constrain extensive deployment in the 1990s. Although there has been extensive experience with the gasification phase, currently, there is only one IGCC plant in operation, the 100 MWe Cool Water plant in California (see figure 4-24). In addition, there is another demonstration plant using a different gasifier, under construction in a large petrochemical plant (discussed more in chapter 9). The Cool Water plant has been very successful in meeting its construction schedule[64] and budget, and in its early operation. As a result it has given confidence to utilities in their consideration of whether to commit to an IGCC. Despite this success, however, more operating experience is likely to be required before there will be major commitment to the IGCC by a very cautious electric utility industry. The Electric Power Research Institute, a major sponsor of the IGCC Cool Water project, anticipates three to four commitments by the end of 1986. If these projects go forward and the shorter lead-time potential of the IGCC is proven, then significant deployment in the mid to late 1990s is quite possible.

Figure 4-24.—The Cool Water IGCC Plant in Southern California



SOURCE: Southern California Edison Co.

Description of a Typical IGCC in the 1990s.—Plausible cost and performance features of a representative IGCC are described in appendix A, table A-6. The reference year considered in the report is 1990, at which time two plants, generating altogether approximately 200 MWe probably will be operating in the United States. The reference plant capacity is 500 MWe, consisting perhaps of five gasifiers,[65] though installations as small as 250 MWe might be preferred. While capable of being built with capacities even smaller than 250 MWe, such smaller installations would be more costly per unit of capacity.[66] The plant would consist of three types of equipment: the gas production, cooling and purification facilities; the combined-cycle system (including gas turbines and steam turbines); and the balance of the plant. Included in the constituents of the latter are fuel receiving and preparation facilities, water treatment systems, ash and process-waste disposal equipment, and in most cases an oxygen plant.

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[64] An interesting discussion of the planning and construction of an IGCC can be found in: Cool Water Coal Gasification Program & Bechtel Power Corp., *Cool Water Coal Gasification Program—Second Annual Progress Report*, interim report (Palo Alto, CA: Electric Power Research Institute, October 1983), EPRI AP-3232.

[65] Zaininger Engineering Co., *Capacity Factors and Costs of Electricity for Conventional Coal and Gasification-Combined Cycle Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3551.

[66] According to one source (Electric Power Research Institute, *Economic Assessment of the Impact of Plant Size on Coal Gasification—Combined-Cycle Plants* (Palo Alto, CA: Electric Power Research Institute, 1983), AP-3084), the levelized cost of electricity for a variety of IGCCs using Texaco gasifiers increased as plant size decreased. The economies of scale were relatively small among plants of capacities greater than 250 MWe. But as plant size diminishes below 250 MWe, levelized costs increase very significantly. Selection of a 500 MWe module also was favored by participants in a June 1984 OTA-sponsored workshop on IGCCs, though it was suggested that installations as small as 250 MWe might seriously be considered.

The IGCC can be built in phases. The design permits the operation of portions of the plant before other segments are completed. The gas turbines could be installed first and operated with natural gas. The steam turbines then could be added, allowing the production of still more electric power. Finally, the gas facilities could be added to complete the plant and to allow its operation based on synthetic gas. Hence, some electrical power could be produced before the entire plant is completed.

The typical plant would require a rather large area of land and considerable quantities of water during its lifetime of approximately 30 years. An estimated 300 to 600 acres would be needed for the facilities, and for disposal of solid wastes. And 3 to 5 million gallons of water, on average, would be required to run the plant daily. These quantities are large, but as noted above, they are smaller than those which characterize conventional pulverized coal plants equipped with scrubbers.

The operating availability of the reference IGCC plant is 85 percent. There is uncertainty associated with availability estimates, as these plants would be the first commercial units and could experience problems which would result in lower availability rates. Of particular concern is the reliability of the combined-cycle system; combined-cycle system design as well as operating and maintenance practices will largely determine combined-cycle reliability.

The IGCC facility commonly would be used to provide base load power at efficiencies ranging from 35 to 40 percent. This corresponds to a heat rate of between 8,533 and 9,751 Btu/kWe-hour.[67] It is worth noting that the Cool Water demonstration plant, which had a design heat rate of 11,400 Btu/kWh, has consistently met that target in operation to date. While the gasifier design certainly has an important effect on efficiency, the most important factor in efficiency within the anticipated range probably would be the gas turbines. To reach the high efficiencies projected for the IGCC will require high-temperature, advanced combustion turbines. The projected efficiency range is somewhat higher than the 35 to 36 percent efficiency expected for conventional plants with scrubbers.[68]

Conventional turbines would yield efficiencies at the low end of the efficiency range, while advanced turbines might yield higher efficiencies.[69] The choice of turbine type could significantly affect O&M costs in addition to efficiency.[70] For example, an advanced turbine design, while promising higher efficiencies could also entail greater technical problems and therefore higher O&M costs. The choice of turbine also would affect capital costs. Higher efficiency turbines would result in a higher electrical output for a given gasifier and feed system; and the steam plant would be relatively smaller. Both changes would reduce capital costs per kilowatt-hour.[71]

Capital costs probably will range from $1,200 to $1,350/kWe (net). For units in the 250 MWe range, costs are expected to be somewhat higher, about $1,600/kWe. By far the largest expense would be the gas production and purification facilities. These might account for approximately 40 percent of total costs. The cost would vary especially with gasifier design; there are indications that substantial capital cost differences may exist among leading gasifier designs,[72] though the magnitude of these differences not clearly established. Costs also will vary significantly according to the degree to which redundancy is designed into the system. Another 40 percent of the cost would include buildings, coal receiving and preparation equipment, an oxygen plant, waste handling equipment, water equipment, and the combined-cycle system.[73] Finally there are access roads, site preparation, and various civil engineering tasks; together these might represent roughly 20 percent of capital costs.

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[67] It is important to note that IGCC heat rates are particularly sensitive to ambient temperatures. Heat rates go down with ambient temperatures. See, for example, table 3-1 in: Zaininger Engineering Co., *Capacity Factors and Costs of Electricity for Conventional Coal and Gasification-Combined Cycle Power Plants*, op. cit., 1984. It is assumed here that ambient temperatures are held constant throughout the year at 88° F.

[68] B.M. Banda, et al., "Comparison of Integrated Coal Gasification Combined Cycle Power Plants With Current and Advanced Gas Turbines," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849507.

[69] Ibid.

[70] For a discussion of relevant turbine developments, see: Eric Jeffs, "Tokyo Congress Highlights Efficiency and Nox Control," *Gas Turbine World*, January-February 1984, pp. 26-30.

[71] General Electric Co., *Review and Commentary on Design of Advanced Fossil Fuel Systems* (Fairfield, CT: General Electric Co., 1982).

[72] OTA staff telephone conversation with Bert Louks, Electric Power Research Institute, June 6, 1984.

Operating and maintenance costs could range from 6 to 12 mills/kWh, a figure roughly equivalent to the costs characteristic of a conventional pulverized coal plant. The greatest source of uncertainty in the estimate concerns the performance of the gasifiers, of the syngas coolers (if they are used) and of the gas turbines.

Fuel costs for the reference plant are projected to range from 15 to 17 mills/kWh based on 1990 coal costs of $1.78/MMBtu (see "Definitions" in appendix A for discussion of fuel costs). It is here where the possible cost advantage of the IGCC over the conventional scrubber equipped plant is greatest. Because of its higher efficiency, the IGCC's fuel costs would be less than those of its conventional counterparts. As discussed above, an important determinant of overall efficiency is the gas turbine's efficiency. Advanced turbines which are expected to be available by the early 1990s would be much more efficient than present turbines. Their use could allow fuel costs to fall to the low end of the estimated range. Since fuel costs account for a large portion of the cost of generating electricity from the IGCC, the anticipated improvement in turbine efficiency will affect the competitive position IGCC significantly.[74]

Atmospheric Fluidized-Bed Combustion

Introduction.—The AFBC is a combustion technology which will provide an economic alternative to conventional pulverized coal plants in the 1990s. Its relatively low volumes of sulfur dioxide and nitrogen oxide emissions, great fuel flexibility, small commercially available size (< 100 MWe), easily handled solid wastes, responsiveness to demand changes, and other features offer advantages which may allow it to compete successfully with conventional plants, particularly in areas where high sulfur coals are used. Investment outside the utility industry in AFBC cogeneration units already is growing rapidly. Greater investment by utilities is likely in the 1990s, though various factors may keep the number of large utility-owned AFBCs operating by the end of the century below that which cost alone would set (see chapter 9).

There are two basic types of fluidized-bed combustors: the atmospheric fluidized-bed combustor (AFBC) and the pressurized fluidized-bed combustor (PFBC). The PFBC operates at high pressures, and therefore can be much more compact than the AFBC. The PFBC also may produce more electricity for a given amount of fuel. Despite these potential advantages, the PFBC has more serious technical obstacles to overcome and is less well developed than the AFBC. It has not yet been successfully demonstrated on a commercial scale, nor are any commercial-scale demonstrations now under construction in the United States. It is unlikely that more than a few commercial units could be completed and operating before the end of the century, though the PFBCs longer term potential is quite promising.

The AFBC, the focus of this analysis, operates at atmospheric pressures. Small-scale AFBCs already are used commercially around the world for process heat, space heat, and in various other industrial applications; and are producing electrical power abroad as well as in very small amounts in the United States. Three types of AFBC installations may be important over the next 15 years: large electric-only plants (100 to 200 MWe), cogeneration installations, and nonelectric systems. The electric-only units are likely to be deployed by utilities, whereas the cogeneration and nonelectric units probably would be built and operated by others.

The cogeneration unit is an installation operated to provide both electricity and usable thermal energy, while the nonelectric systems are used to supply usable heat only. Electric-only AFBCs may be new "grass-roots" plants built from the ground up; or they may be "retrofits" to existing plants which have been modified to accommodate an AFBC instead of the old conventional boilers.[75] A retrofit may allow the life of a powerplant to be prolonged, reduce emissions, and increase the rating of a powerplant. Retrofits also are cheaper and faster to build than completely new AFBCs. See chapter 5 for a more detailed discussion of retrofits.

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[73] H.G. Hemphill and M.B. Jennings (Raymond Kaiser Engineers, Inc.), "Offsites, Utilities, and General Facilities for Coal Conversion Plants," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849195.

[74] B.M. Banda, et al., "Comparison of Integrated Coal Gasification Combined Cycle Power Plants With Current and Advanced Gas Turbines," op. cit., 1984.

While this discussion centers on the large, grass-roots electric-only plants, the other three types of installations—retrofit, cogeneration, and nonelectric units—are important for several reasons. First, they constitute the most immediate market for the AFBC; and may very well dominate the market in the 1990s (see chapter 9). This prospect is enhanced by their short lead-times—substantially shorter than those which would characterize large grass-roots, electric-only units.[76]

Second, operation of these units may provide valuable experience which can be used to rapidly refine the technology, to reduce cost uncertainties and to improve its competitive posture. Thus, even with very few grass-roots, electric-only plants in operation, their design can be continuously and quickly improved and risks reduced as a result of experience gained in other applications. Furthermore, where utility retrofits are concerned, utilities directly can gain operating experience and confidence in the technology at a cost and risk considerably smaller than that associated with a new grass-roots electric-only plant.

General Features of the AFBC.—A fluidized-bed is a mass or "bed" of small particles—solid fuel, ash and sorbents used for sulfur removal—through which flow large volumes of air and combustion gases. The gases move through the bed at velocities sufficient to cause the mass of particles to behave like a fluid; hence the term "fluidized-bed." In the AFBC, one or more fluidized beds are used to perform two key functions: combustion of the fuel and capture of sulfur carried in the fuel. Some AFBCs perform both functions in a single bed. Other systems use several sequentially linked beds, each of which has a different design and performs a different function. For the sake of simplicity, this discussion focuses on AFBCs which require only one bed.

In the typical AFBC, unburned solid fuel regularly is fed into the bed and mixed with the bed's hot particles bringing about combustion. Thermal energy is removed from the bed by heat transfer to water carried in tubes passing through the bed. The resultant steam can be used indirectly for space or process heat, to drive a steam turbine, or both. If the fuel contains substantial quantities of sulfur, a chemically active "sorbent" such as limestone also is fed into the bed to react with the sulfur while it is still in the bed. The sorbent captures the sulfur before it escapes from the bed with the combustion gases. This capability to capture sulfur "in situ" reduces or eliminates the need for expensive add-on sulfur-removal equipment and is perhaps the most attractive feature of the AFBC.

Air is injected from below the fuel and sorbent mixture and "fluidizes" it. Depending on the velocity and volume of the air, and the size of the fuel and sorbent particles, a portion of the particles and combustion byproducts are entrained in the flow of air and "elutriated" from the bed. A cyclone[77] separates the larger entrained particles from the gases. The gases and smaller particles are cooled and discharged into a baghouse[78] where the remaining particles are removed from the gas before it is exhausted to the atmosphere. The solids removed in the cyclone meanwhile are recycled through the bed—to improve fuel and sorbent utilization—or discharged. Some solids also may be discharged from the bottom of the bed. The effective recycling of sorbent and of unburnt materials is crucial in maintaining a highly efficient combustion process and minimizing sorbent consumption.

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[75] The retrofit can take one of two forms. The old boiler may be *modified* with the addition of an AFBC; or the old boiler may be removed in its entirety and replaced with an entirely new AFBC boiler. In either case the old turbine and other equipment may be used.

[76] Retrofit units in many cases involve very little regulatory delay, as they are deployed at preexisting plants. Cogeneration units and nonelectric units commonly are very small, and are not owned by utilities, and are are not subject to the same extensive regulatory delays which characterize large utility-owned projects.

[77] A cyclone is a mechanical device which separates particles from gases by using centrifugal force.

[78] A system of fabric filters (bags) for dust removal from stack gases.

Fluidized-bed combustors are commonly categorized by the degree to which solids are entrained in the gas-flow through the bed and to which solids are recycled to the bed after passing through the cyclone. The primary types of fluidized-beds are illustrated in figure 4-25; among these, bubbling beds and the circulating beds are the most important.[79]

The *bubbling bed* AFBC is characterized by low gas velocities through the bed. The result is a bed from which only the smaller particles are entrained with the gas; after being entrained, the solids on the average are recycled through the bed less than once. Conversely, the gas flow velocities through the circulating bed are rapid. The bed itself becomes less distinct with greater en-

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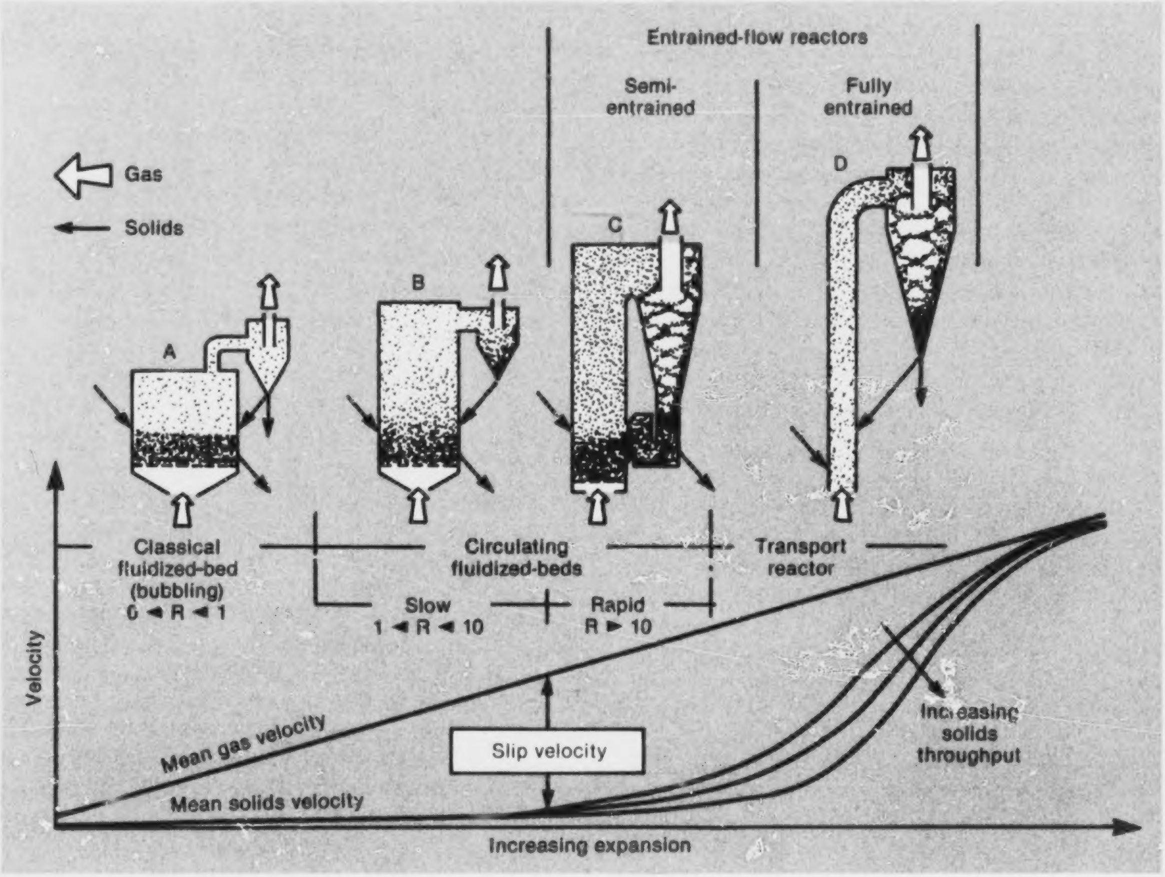
[79] These in turn can be further subdivided. Among the bubbling beds are the conventional bubbling bed, multibed and in-bed circulating models. Circulating systems include conventional and multisolids bed (or hybrid) systems. (Bruce St. John, NUS Corp., *Analysis and Comparison of Five Generic FBC Systems*, paper presented at Fluidized Bed Combustion Conference, sponsored by the Government Institutes, May 1984.)

Figure 4-25.—Types of Fluidized Gas-Solid Reactors With Different Regimes of Particle Slip Velocity and Degrees of Flyash Recycle (with Reh) Showing Proposed Terminology



Entrained-flow reactors
Semi-entrained
Fully entrained
Gas
Solids
A
B
C
D
Classical fluidized-bed (bubbling) 0 ◄ R ◄ 1
Circulating fluidized-beds
Slow 1 ◄ R ◄ 10
Rapid R ► 10
Transport reactor
Velocity
Mean gas velocity
Slip velocity
Mean solids velocity
Increasing solids throughput
Increasing expansion

$$R = \frac{\text{Mass flow rate of solids returned to bed}}{\text{Mass flow rate of solids entering bed}}$$

SOURCE: Leon Green, Jr., *Value Derivable From Coal Waste by Entrained-Flow Combustion*, presented at the Fifth ICU Symposium, Pittsburgh, PA, June 1983.

trainment levels, as larger portions of the fuel and sorbent repeatedly are cycled through the combustor. The fuel and limestone are thoroughly mixed as combustion of the fuel takes place.

Each of the two types of AFBC possesses certain operating characteristics and peculiarities. An important shortcoming shared by both technologies is the fact that neither have been built to produce electric power on a scale—100 to 200 MWe—attractive to utilities. And both face serious technical challenges in moving from the very small nonelectric industrial boilers which have typified AFBC applications so far to these larger sizes.

The bubbling bed has an important advantage in that it is the older of the two types and there is greater operating experience in the United States (in small, nonelectric, industrial applications). The bubbling-bed combustor can more readily be retrofitted to some preexisting conventional boilers. But the design also has its drawbacks. Perhaps the most serious are the fuel-feed problems encountered as the unit is scaled-up. It is difficult to design a reliable feed mechanism that adequately distributes fuel to the bed; the problem becomes progressively more difficult as the bed is enlarged. An elaborate feed design is required; and the size and moisture content of the fuel must be carefully controlled.

By the end of this decade several large bubbling-bed AFBCs will be operating in the United States. One is a grass-roots, 160 MWe demonstration plant in Paducah, Kentucky (see figure 4-26). Two others are retrofit units. Among the units, two different feed systems will be used. Should serious problems be encountered in the feed systems of the units, the deployment of the bubbling beds with capacities between 100 and 200 MWe in the 1990s may be seriously delayed. Favorable operation would encourage commercial orders of large units. Other problems associated with some bubbling bed designs, which may impede commercial deployment, are erosion and corrosion of materials which are in contact with the bed itself or particulate laden gases. These difficulties, should they persist, could result in unacceptably high O&M costs.

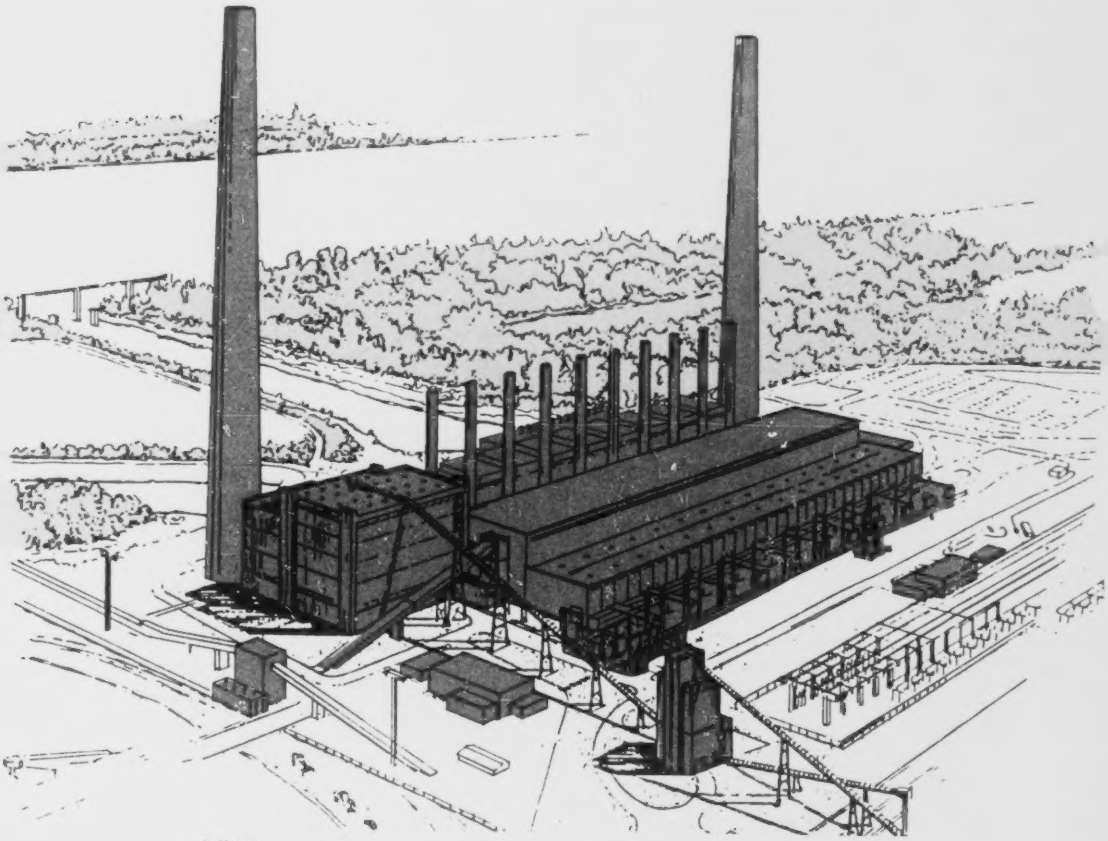
With the *circulating bed,* by virtue of its greater gas velocities and higher levels of particulate recycling, the fuel-feed problem may be far less of a problem, at least with smaller units. A simpler feed mechanism can be used, and larger variations in fuel size and moisture are tolerated. Efficient combustion and sorbent utilization is more readily achieved. Nitrogen oxide and carbon monoxide emissions also tend to be lower.

Being a newer "second-generation" technology, there is less experience operating even small circulating-bed AFBCs. But this disadvantage is rapidly disappearing. Many vendors now are offering circulating beds; and almost all the major cogeneration units and many of the nonelectric AFBC projects now being built employ circulating beds.

While it is not clear whether plants using bubbling beds, circulating beds, or some hybrid of the two will be favored for large grass-root plants in the 1990s, the recent commercial trends indicates that the circulating beds are becoming the technology of preference for small cogeneration uses and a sizable share of nonelectric applications. Favorable experience with these units, as well as the single large retrofit unit using the circulating bed, could decisively favor the competitive position of large circulating bed AFBCs in the 1990s. As with the large bubbling bed demonstration units, however, difficulties with the demonstration retrofit unit could seriously retard the commercial deployment of large units.

Typical AFBC Plant for the 1990s.—A large AFBC plant typical of the kind which might might be deployed for electricity production in the 1990s is described in appendix A, table A-5. The table and the following discussion focus on all-electric, grass-roots plants. By the early 1990s, U.S. utilities will have only one such plant on which to base evaluations of the technology. This is the 160 MWe demonstration unit which currently is being constructed at TVA's Shawnee Steam Plant in Kentucky; startup is scheduled for 1989. Investors, however, also by the early 1990s will benefit from the technical progress and information resulting from two large demonstration retrofit units, one of 100 MWe and the other of

Figure 4-26.—160 MW AFBC Demonstration Plant in Paducah, KY



Authority

125 MWe, which also will have operated for several years by the early 1990s. Also important will be experience gained from the operation of a fully commercial, 125 MWe cogeneration unit—also a retrofit—being installed by a private firm in Florida. And many hundreds of megawatts of small AFBCs will have been installed by 1990.

The reference AFBC plant considered in the analysis has a generating capacity of approximately 150 MWe (net). The gross electrical power production of the plant actually would exceed net capacity, because power is required to operate the equipment which circulates the solids and forces air into the bed. Any commercial units considered in the early 1990s are not likely to exceed by very much the size of the demonstration units; AFBCs are subject to scale-up problems which probably will inhibit during the 1990s deployment of any commercial units much larger than the demonstration plants.

Many features of the AFBC installations deployed in the 1990s, regardless of type, are likely to be much the same. They will require access to coal and limestone supplies; this usually means railroad access. A rather sizable piece of land will be required, not only for the AFBC itself but for coal and limestone handling and processing facilities, storage areas for the limestone and coal, disposal areas for the solid waste generated by the plant, and ponds of various sorts. Disposal of spent limestone may be one of the most serious problems for the AFBC. Current estimates are that about 1,200 tons per MWe year need to be disposed of for 3.5 percent sulfur, Illinois coal.

For a 150 MWe plant, about 90 to 218 acres could be required; the exact amount depends on several conditions. Access to water also will be required; the 150 MWe reference plant is expected to require about 1.5 million gallons each day.

Like any large powerplant, the AFBC is expected to require a considerable amount of time to deploy. An AFBC in the 100 to 200 MWe range potentially has a lead-time of no more than 5 years because of its smaller size and environmental benefits. As with the IGCC, however, lead-times of the first plants are likely to be greater, and could be as long as 10 years. This includes up to 5 years for design, preconstruction, and licensing activities; and 2 to 5 years for construction. Favorable regulatory treatment, and rapid and quality construction could result in lead-times close to the potential.

If in fact large, grass-root AFBC plants take up to 10 years to build from initial commitment, orders for them must be made by 1990 for the AFBCs to contribute appreciably to generating capacity before the close of the century. Given the fact that the three large demonstration plants and numerous small cogeneration units will be operating by then, there is a possibility that considerable numbers of large plants indeed will be initiated by that time.

The operating availability of an AFBC powerplant may be around 85 to 87 percent. But considerable uncertainty surrounds this figure. Difficulties with the fuel feed system in bubbling-bed AFBCs could severely reduce operating availability. Or erosion or corrosion associated with both bubbling-bed and circulating-bed AFBCs could have similar effects.

AFBCs are expected to be used primarily as base load plants, though their demand-following capabilities will allow their use in intermediate applications. An AFBC plant is expected to last for approximately 30 years, and to operate with an efficiency of approximately 35 percent—somewhat higher than a conventional pulverized coal plant equipped with scrubbers.

The capital cost of a large AFBC probably will be pegged at a level roughly comparable to that of its main competitors, the conventional scrubber-equipped plants and the IGCC. The estimate in this analysis is $1,260 to $1,580/kWe. Fuel costs are expected to be approximately 17 mills/kWh assuming coal costs of $1.78/MMBtu. O&M costs are expected to fall between 7 and 8 mills/kWh, but high uncertainty is associated with this estimate. Should technical problems be experienced with the fuel feed system, or should serious erosion or corrosion problems arise, power production could suffer and expensive repairs and modifications could be required. Consequently, O&M costs could escalate.

The major opportunities for research which could yield technical improvements in the AFBC or reduce uncertainty about performance lie in the three large demonstration projects which currently are underway. These projects offer the chance to experiment with basically different designs and to compare technologies. Of particular importance will be research relating to the fuel feed systems and to designs and materials which can reduce erosion and corrosion of system components.

ENERGY STORAGE TECHNOLOGIES

Introduction

There are several tasks that electric energy storage equipment, employed by utilities, can perform. The most common is *load-leveling,* in which inexpensive base load electricity is stored during periods of low demand and released during periods when the marginal cost of electricity is high. In addition, storage equipment can be used as *spinning reserve,* the backup for generating systems which fail, or as *system regulation,* the moment-by-moment balancing of the utility's generation and load.

Energy storage technologies also may be used by utilities' customers in either remote or grid-connected applications. The latter typically involve the use of storage devices by utility customers wishing to avoid the high price of electricity during peak periods. Cheaper power is purchased during base periods and stored for use during higher cost, peak periods.

Modular storage technologies, such as batteries and flywheels, can be deployed in either a utility-owned or in a nonutility-owned dispersed fashion. However, economic considerations currently seem to favor large utility- or third-party-owned installations. While storage technologies may at some point be installed in conjunction with large deployments of intermittent generating plants, such as photovoltaics or wind, storage facilities in the 1990s will most likely be used to store the inexpensive output of large, conventional plants.[80]

There are two storage technologies which could, under some circumstances, see significant deployment in the 1990s: advanced batteries and compressed air energy storage (CAES). Batteries are a well-established technology, familiar mostly in mobile applications, but only recently have advances in chemistry and materials made it possible to construct large-scale systems with sufficiently long lifetimes and low capital costs to attract utility interest.

A CAES plant is a central station storage technology in which off-peak power is used to pressurize an underground storage cavern with air, which is later released to drive a gas turbine. The technology has been demonstrated in Europe, but not in the United States.

Compared to batteries, CAES plants have several advantages. They are in a more advanced stage of technical development and are likely to be less expensive than batteries on a dollar per kilowatt-hour basis when long discharge times (roughly 5 hours or more) are required. However, compared to batteries, CAES plants are less modular, and thus carry more financial risk per project.

Among the storage technologies not likely to make a significant additional contribution in the 1990s are pumped hydro, flywheels, and superconducting magnet energy storage. While there are numerous pumped hydro plants in existence in the United States, it has become difficult to site these plants if they involve a large, above-ground reservoir. If all the water is stored underground, the plants are economic only in very large units.[81] Flywheels, while possibly competitive in small installations, e.g., cars or homes, cannot compete economically with batteries or CAES in larger installations.[82] Finally, superconducting magnetic energy storage is not likely to be commercial before the next century.

Compressed Air Energy Storage

Introduction

A CAES plant uses a modified gas turbine cycle in which off-peak electricity—stored in the form of compressed air—substitutes for roughly two-thirds of the natural gas or oil fuel necessary to run an equivalent conventional plant (see figure 4-27). In a conventional plant, the turbine must power its own compressor to supply the compressed air necessary for operation. This makes only a third of the turbine's power available to produce electricity. In a CAES plant, however, off-peak electricity is used to drive the compressor (through the generator running in reverse as a motor) which charges an underground storage cavern with compressed air. Later the air is released and passes through a burner where a hydrocarbon fuel such as natural gas is burned.[83] The resulting hot gases then pass through a turbine which, freed from its compressor, can drive the electric generator with up to three times its normal fuel efficiency. The gases discharged from

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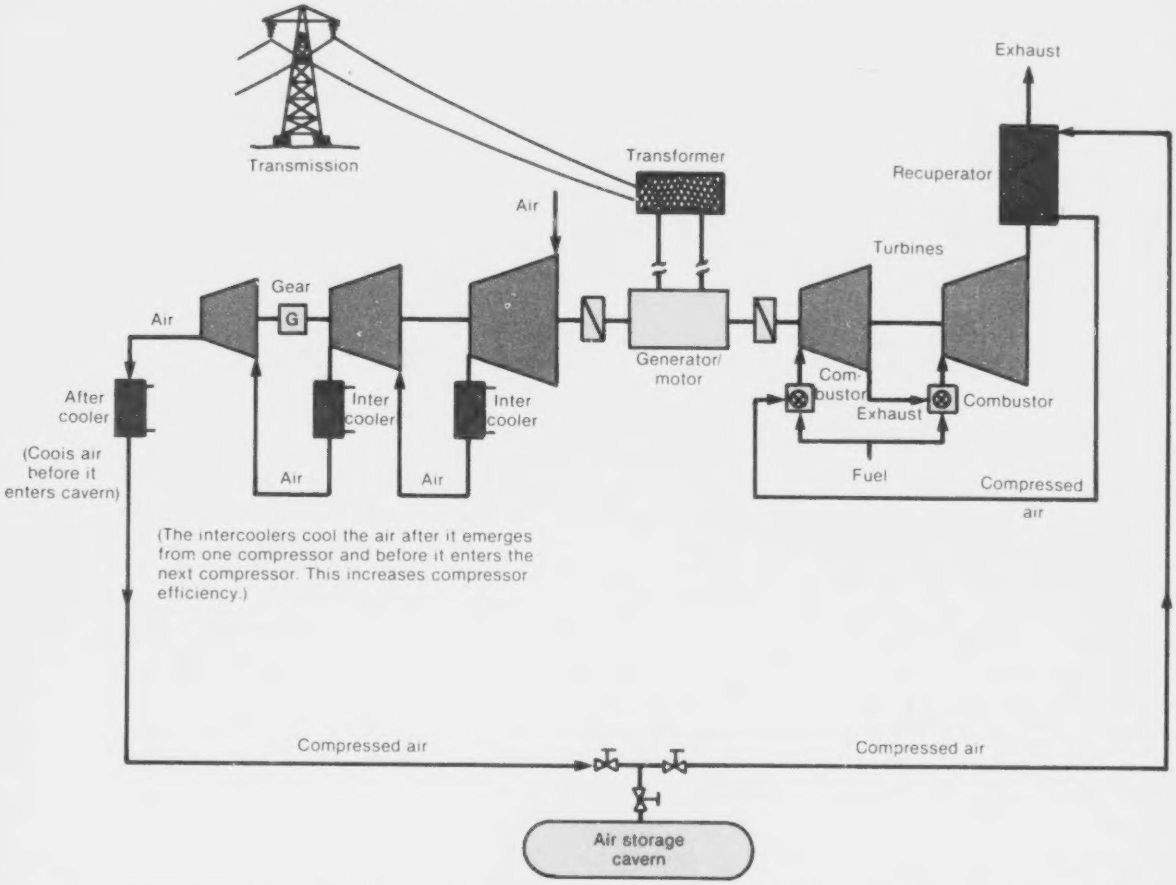
[80] As currently is the common practice with pumped hydroelectric facilities; there may be some exceptions, however, in certain isolated areas with large potential for renewables, such as Hawaii.

[81] Peter E. Schaub, Potomac Electric Power Co., comments on OTA electric power technologies November 1984 draft report, Jan. 29, 1985.

[82] James H. Swisher and Robert R. Reeves, "Energy Storage Technology," *Energy Systems Handbook* (New York: John Wiley & Sons, February 1983).

[83] In addition to the CAES technology described here, there are several, more advanced CAES systems which reduce or eliminate the need for natural gas or hydrocarbon fuel. These systems would be more expensive than the more conventional CAES systems, and while none have yet been demonstrated, they could be developed for the 1990s with sufficient utility interest.

Figure 4-27.—First Generation CAES Plant


Transmission
Transformer
Exhaust
Recuperator
Air
Turbines
Gear
G
Air
Generator/ motor
After cooler
Inter cooler
Inter cooler
Com- bustor
Exhaust
Combustor
(Coois air before it enters cavern)
Air
Air
Fuel
Compressed air
Compressed air
Compressed air
Air storage cavern

(The intercoolers cool the air after it emerges from one compressor and before it enters the next compressor. This increases compressor efficiency.)

A Compressed Air Energy Storage (CAES) plant is a modification of a conventional gas turbine cycle. Its principal components are combustion turbines, compressors, a generator/motor, and an underground storage cavern. The system stores energy by using electricity from the grid to run the compressor and charge the cavern with compressed air. This energy is discharged by releasing the compressed air to the combustion turbine where it is mixed with natural gas or oil and burned to produce the power which drives the generator. In a conventional gas turbine plant the turbine drives its own compressor simultaneously with the generator so that only a third of the turbine's total power is available to produce electricity. Thus, a CAES plant stores the energy in off-peak electricity to make a gas turbine three times as fuel efficient.

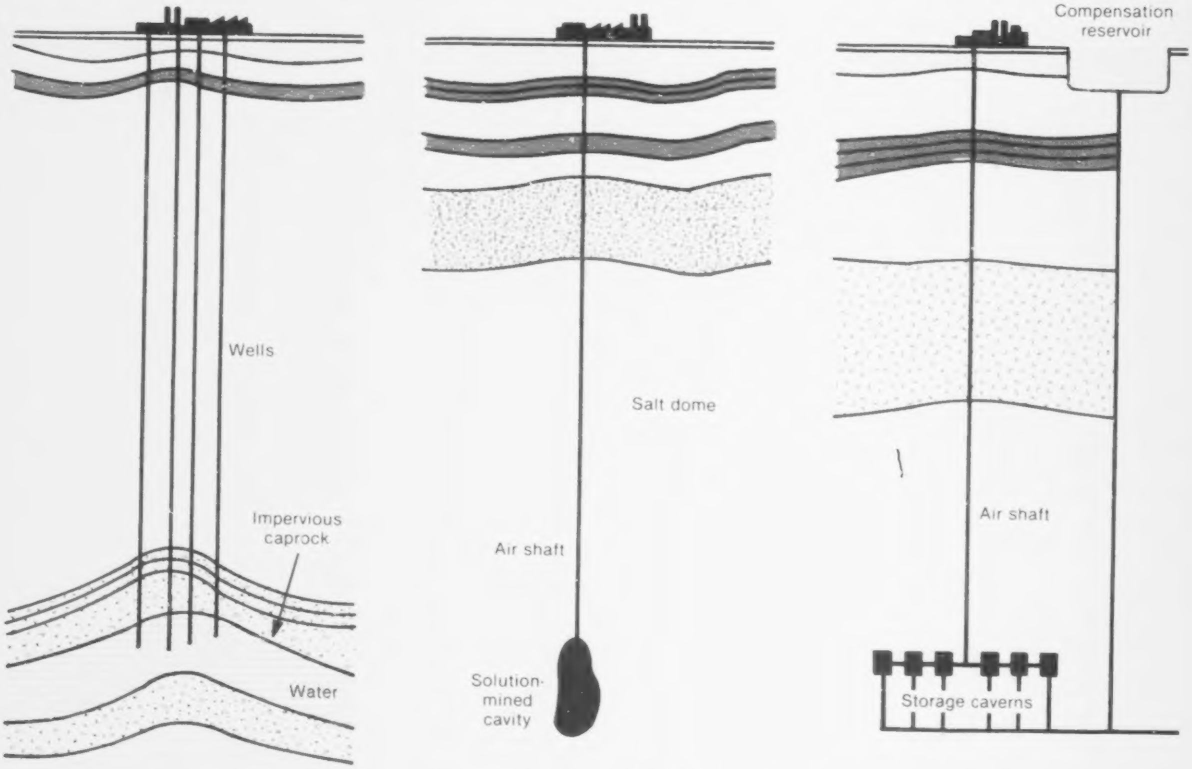
SOURCE: Robert B. Schainker, *Executive Overview: Compressed Air Energy Storage (CAES) Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1983).

the turbine pass through a "recuperator" where they discharge some of their heat to the incoming air from the cavern; this, too, increases the overall efficiency of the plant.

Three types of caverns may be used to store the air: salt reservoirs, hard rock reservoirs, or aquifers (see figure 4-28). Each has its advantages and disadvantages. About three-fourths of the United States rests on geology more or less suitable for such reservoirs (see figure 7-12 in chapter 7). The salt domes are concentrated mostly in Louisiana and eastern Texas. Salt caverns are "solution-mined" by pumping water into the deposit and having it "dissolve" a cavern. The resulting reservoir is virtually air-tight. These salt caverns are pressurized to up to 80 atmospheres, have a depth of 200 to 1,000 meters, and a volume of 1,000 cubic meters/MWe.

Rock caverns are located throughout the United States. They must be excavated with underground mining equipment. A typical CAES plant using a rock cavern would be coupled to

Figure 4-28.—Geological Formations for CAES Caverns



In an aquifer system, numerous wells are sunk through an impervious caprock into porous material such as sand, sandstone, or gravel. The force of the surrounding water confines the compressed air and maintains it at a constant pressure as it is injected and withdrawn from the system.

Salt caverns are mined by a technique called solution-mining. A narrow well is drilled into a salt dome and fresh water is continuously pumped in to dissolve the salt while the resultant brine is pumped out. The process is continued until the desired storage volume is reached. The necessary volume is larger than that needed in a hard rock or aquifer system because without water present, the pressure of the compressed air drops as it is withdrawn from the cavern.

Hard rock caverns are mined with standard excavation techniques. A compensation reservoir on the surface maintains a constant pressure in the cavern as the compressed air is injected and withdrawn. This minimizes the volume of rock it is necessary to excavate.

SOURCE: "Eighty Atmospheres in Reserve" *EPRI Journal*, April 1979.

an above-ground compensating reservoir which would maintain a constant pressure in the cavern as it discharges. The maintenance of constant pressure offers several important operational advantages. In addition to maintaining the desired pressure, the reservoir also allows for a much smaller cavern than is the case with salt reservoirs. Thus, only about 600 cubic meters/MWe are needed underground, though a pool of about 700 cubic meters/MWe of water is required on the surface.[84]

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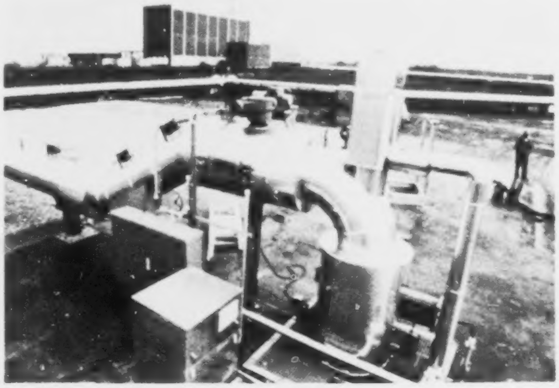
[84] Use of a compensating reservoir is less suitable for salt reservoirs because the salt dissolves in the water. This can only be prevented by the use of water saturated with salt, an approach which could result in major environmental problems.

The aquifer reservoirs are naturally occurring geological formations found in much of the Midwest, the Four Corners region, eastern Pennsylvania and New York. An advantage of this kind of reservoir is that it does not require any excavation. It consists of a porous, permeable rock with a dome-shaped, nonporous, impermeable cap rock overlying it. Compressed air is pumped into the reservoir, forcing the water downward from the top of the dome. Later, as air is drawn from the reservoir, the water returns to its original place beneath the dome. An important advantage of this kind of reservoir lies in the fact that the volume of the reservoir is quite flexible, allowing for a variety of plant capacities and operating schedules.

With the exception of the recuperator, the technologies required for CAES plants—the turbomachinery and the reservoir-related technologies such as mining equipment—are well-established technologies. The turbomachinery is only a slight modification of currently used equipment and there are several manufacturers, American and foreign, that offer CAES machinery with full commercial guarantees. While there are some questions as to the dynamic properties of the air as it enters and leaves a cavern, there is little doubt that the technology exists to build and maintain underground storage facilities. These caverns have been used for years to store natural gas and other hydrocarbons, and the same firms that supply the oil and gas industry have offered to provide utilities with CAES caverns that can be warrantied and insured.[85]

Despite the relative maturity most of the components which make up the CAES plant, there has been no experience in the United States with CAES itself—though a CAES plant using a salt cavern has been in operation since 1978 at Huntorf, West Germany (see figure 4-29) and has performed well. This lack of domestic experience with the technology constitutes the largest hurdle facing CAES. There is a general reluctance among utilities in this country to be the first to make a commitment to build a plant. While several utilities have made preliminary planning studies, the Soyland Electric Cooperative in Illinois is the only American utility that has ordered a plant. This plant, however, was for various reasons canceled and no project has been initiated since then.

Figure 4-29.—The Huntorf Compressed Air Energy Storage Plant in West Germany



In the foreground is the wellhead, where compressed air is injected and released. The rest of the plant is in the background.

SOURCE: BBC Brown Boveri, Inc.

Typical CAES Plant for the 1990s

CAES plants in the 1990s are likely to be available in two modular unit sizes, 220 MWe, commonly called *maxi-CAES*, and 50 MWe, *mini-CAES*. These sizes are determined by the sizes of existing models of turbomachinery—the turbines, compressors, generator/motor, and a gearbox which connects them.

A CAES plant must be sited in an area with access to water and fuel. The turbomachinery requires about 2,000 gallons/MWe of water per day, and a plant with a rock cavern needs additional water for the compensation reservoir. Both mini- and maxi-CAES plants burn about 4,000 Btu/kWh of fuel and emit the standard combustion byproducts, such as nitrogen oxide, but at only a third of the level of a similar size conventional gas turbine. CAES plants also have noise levels similar to those of more conventional plants. There are several waste disposal problems involved with building the caverns. If a rock cavern is used, it is necessary to dispose of a large volume of waste rock,[86] and when a salt cavern is used, the brine pumped out of the cavern must be disposed of. Land requirements would range from around 15 acres for a maxi-CAES plant to 3 acres for a mini-CAES plant.

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[85] Personal correspondence between Arnold Fickett (Electric Power Research Institute) and OTA staff, July 2, 1984.

The lead-times expected for CAES plants will probably range from 4 to 8 years. The large plants would occupy the higher end of the range, while the smaller units would fall at the lower end. The primary source of uncertainty in lead-time estimates concerns licensing and permitting, which is expected to take 2 to 4 years. Regulatory hurdles will vary depending on the type of reservoir used. Among the regulatory impediments are those relating to the disposal of the hard rock or brine from the mining operation, and relating to water usage and impacts. Also problematic may be the requirements of the Powerplant and Industrial Fuel Use Act of 1978. Even though a CAES plant is an oil and gas saving device, the fact that it uses these fuels means a utility must receive an exemption from the act to operate one. A precedent was established when such an exemption was granted to the Soyland Electric Cooperative, but under the current regulations, exemptions would be required for every CAES plant.[87]

The properties of the two sizes are similar (see table A-8, appendix A); the mini-CAES turbomachinery costs somewhat less—$392/kWe vs. $515/kWe for the maxi-CAES. The storage caverns can be formed out of three types of geological formations: aquifers, salt deposits, and hard rock. In general, aquifers are the least expensive, followed closely by salt. Rock caverns, which must be excavated, are by far the most expensive. On a total dollars per kilowatt basis, caverns for maxi-CAES plants are less expensive than those for mini-CAES.

Advanced Batteries

Introduction

Batteries are more efficient than mechanical energy storage systems, but their principal advantage is flexibility. Batteries are modular so that plant construction lead-times can be very short and capacity can be added as needed. Batteries have almost no emissions, produce little noise (though because of pumps and ventilation systems, they are not silent), and they can be sited near an intended load, even in urban areas. A battery's ability to rapidly begin charging or discharging (reaching full power in a matter of seconds, as opposed to minutes for a CAES system) makes it valuable for optimizing utility operations. However, battery-storage installations do not benefit very much from economies of scale either in capital costs or in maintenance costs, so that if large blocks of storage are required, CAES may be less expensive. Also, though cost effective and reliable in numerous remote applications, battery technology has not yet achieved the combination of low cost, good performance, and low risk necessary to stimulate investment in grid-connected applications.

There are two types of utility-scale batteries which under some circumstances could be particularly important in the 1990s: *advanced lead-acid batteries*, and *zinc-chloride batteries*. Lead-acid batteries are in wide use today mostly in automobiles and other mobile applications; advanced lead batteries constitute an incremental improvement over the existing technology. Zinc-chloride batteries are a newer technology, and constitute a fundamental departure from the conventional lead-acid battery. In both cases, individual modules similar to commercial modules which might be deployed in the 1990s, have been tested at the Battery Energy Test Facility in New Jersey.[88] Though neither type of battery has been deployed yet in a multimegawatt commercial installation, plans to do so during the late 1980s are being developed and implemented.

Other battery technologies meanwhile are being pursued. Among these, the most promising appear to be zinc-bromide batteries and sodium-sulfur batteries. But the development of both lags considerably behind that of the lead-acid and zinc-chloride batteries. Neither has been tested at the BEST facility; such tests are not likely to begin until 1989-90. Given the subsequent need for full-scale commercial demonstration installations and other time-consuming steps, it is very unlikely that either the zinc-bromide or sodium-sulfur batteries could be extensively deployed commercially in the 1990s. Several other advanced battery technologies, such as Iron/Chromium, Zinc/Ferricyanide, Nickel/Hydrogen, and Lithium/Iron Sulfide cells, are all considered even less developed and are not considered here either.

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[86] This problem is greatly alleviated by the fact that the excavated material can be used in constructing the compensating reservoir or other facilities (Peter E. Schaub, comments on OTA electric power technologies November 1984 draft report, op. cit., 1985).

[87] P.L. Hendrickson, *Legal and Regulatory Issues Affecting Compressed Air Energy Storage* (Richland, WA: Pacific Northwest Laboratory, July 1981), PNL-3862, UC-94b.

[88] See ch. 9 for further details on this facility.

Typical Battery Installation for the 1990s

If battery technology is deployed in the 1990s by utilities, the general requirements of a typical plant, regardless of the battery technology employed, are expected to be a peak power output of 20 MWe and a storage capacity of about 100 MWh. Such a plant could consist of about 10 to 50 factory built modules, along with control and power conditioning equipment, housed in a protective building (see figures 4-30 and 4-31). Battery installations outside the utility-industry might be considerably smaller.

The total land necessary will depend on both the so-called "energy footprint" (energy density in kilowatt-hour per square meter) of the particular battery technology as well as the amount of space necessary for easy maintenance. Each of the reference battery installations discussed here will require about 0.02 to 0.03 acres. There are no fuel and only minimal water requirements.

The lead-time required to deploy battery installations is expected to be very short. Because of the comparatively low environmental impacts of the installation, licensing could proceed quite rapidly. And since the battery modules are factory built, construction can be very rapid too. The lead-time of the plant should be less than 2 years. There is, however, uncertainty regarding the time required for licensing and permitting. Concern over possible accidents and disposal of hazardous materials, discussed in greater detail below, could be a source of regulatory delays particularly when the installations are dispersed in urban areas.[89]

Though the battery installations will share many characteristics, other features of the battery plants will differ significantly, depending on the type of battery used. These individual characteristics therefore are treated separately below for each of the two battery types emphasized in this analysis.

Advanced Lead-Acid Batteries.—When fully charged, a lead-acid battery consists of a negative lead electrode and a positive lead dioxide electrode immersed in an electrolyte of sulfuric acid (see figure 4-32). As the battery discharges, the electrodes are dissolved by the acid and replaced by lead sulfate, while the electrolyte becomes water. When the battery is recharged, lead is deposited back on the negative electrode, lead peroxide is deposited back on the positive electrode, and the concentration of acid in the electrolyte increases.

The main advantage of lead-acid batteries is that the technology has been used for decades. It is likely that utility-sized batteries can be produced with sufficient performance characteristics for utility use. At present, it is possible to buy a load-leveling lead-acid battery with a guaranteed lifetime of 1,500 cycles.[90] Accelerated testing results indicate that refinements of the current design can probably bring the lifetime up to 3,000 to 4,000 cycles.[91] While such tests must always be regarded with caution, the many years of experience with accelerated testing of this technology lends confidence to these estimates. However, 4,000 cycles probably represents a limit on the lifetime attainable with current lead-acid battery technology.[92]

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[89] See:

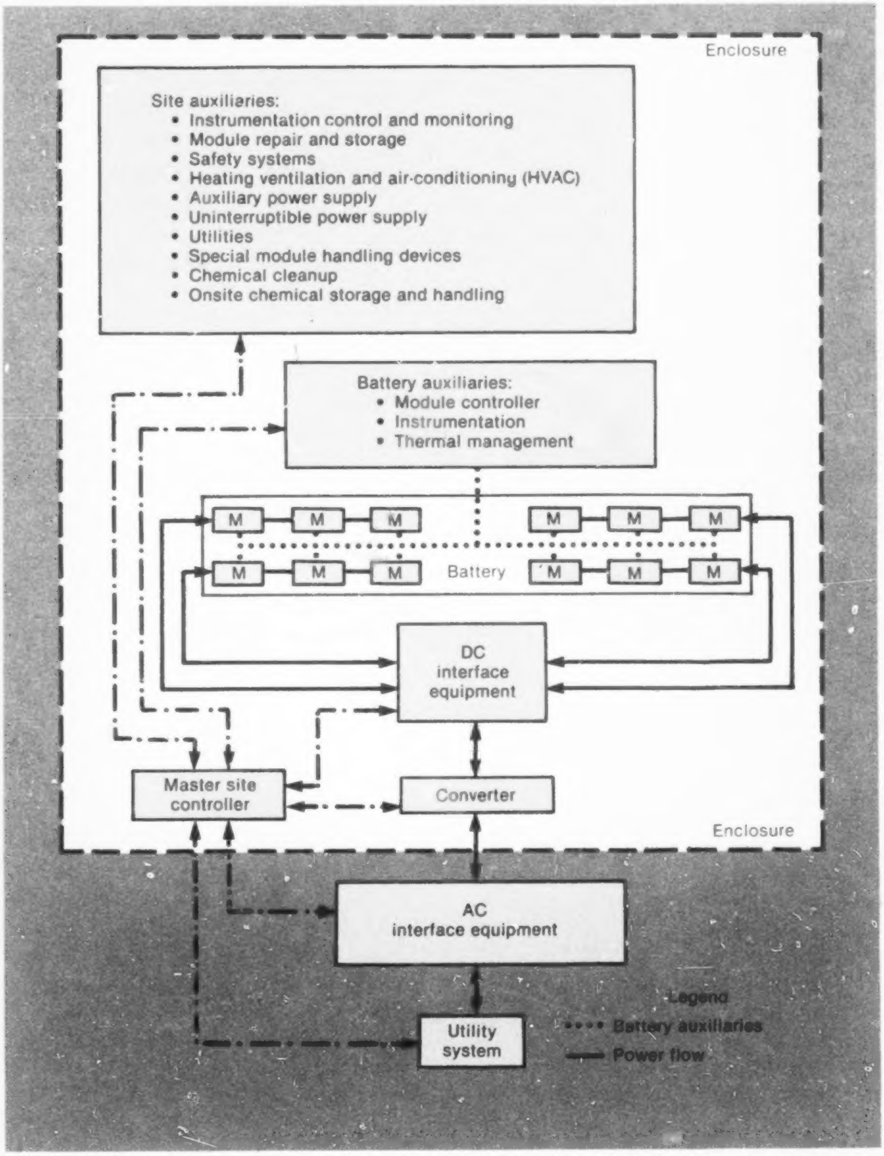
1. Bechtel National, Inc., *Generic Environmental and Safety Assessment of Five Battery Energy Storage Systems* (San Francisco, CA: Bechtel National, Inc., December 1981), DE82-902212.
2. J. Abraham, et al., Public Service Electric & Gas Co., *Balance of Plant Considerations for Load-Leveling Batteries (draft report)*(Newark, NJ: Public Service Electric & Gas Co., 1984).

[90] OTA staff interview with Arnold Fickett, Electric Power Research Institute, Aug. 30, 1984.

[91] Exide Management and Technology Company, *Research, Development, and Demonstration of Advanced Lead-Acid Batteries for Utility Load Leveling* (Argonne, IL: Argonne National Laboratory, August 1983), ANL/OEPM-83-6.

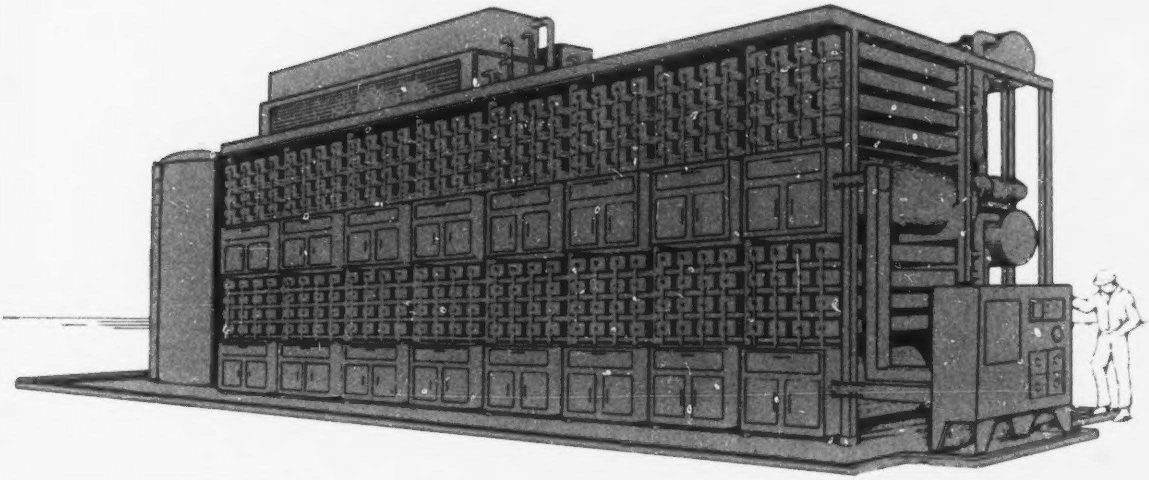
[92] OTA staff interview with Arnold Fickett, op. cit., 1984.

Figure 4-30.—Generic Battery System


Enclosure
Site auxiliaries:
• Instrumentation control and monitoring
• Module repair and storage
• Safety systems
• Heating ventilation and air-conditioning (HVAC)
• Auxiliary power supply
• Uninterruptible power supply
• Utilities
• Special module handling devices
• Chemical cleanup
• Onsite chemical storage and handling
Battery auxiliaries:
• Module controller
• Instrumentation
• Thermal management
M
Battery
DC interface equipment
Master site controller
Converter
Enclosure
AC interface equipment
Utility system
Legend
Battery auxiliaries
Power flow

SOURCE: Peter Lewis, Public Service Electric & Gas Co. (Newark, NJ), "Elements of Load-Leveling Battery Design for System Planning," presented at the International Symposium and Workshop on Dynamic Benefits of Energy Storage Plan Operation.

Figure 4-31.—A Commercial Load-Leveling Zinc-Chloride Battery System



This system is known as the FLEXPOWER System, developed by Energy Development Associates. This particular system is rated at 2 MWe, and can operate from 3 to 4 hours.

SOURCE: B.D. Brummet, et al., "Zinc-Chloride Battery Systems for Electric Utility Energy Storage," presented at the 19th Annual Intersociety Energy Conversion Engineering Conference, San Francisco, CA, Aug. 19-24, 1984.

The main problem with lead-acid batteries is the capital cost. (See appendix A, table A-9.) The price of lead has recently dropped, primarily because its use in paint and gasoline is legally prohibited in many instances. At this low price, the lead alloy and other active materials contribute about one-fourth of the battery's projected selling price of $600/kWe.[93]

This is close to the $500/kWe cost at which batteries are generally considered to be economic. The battery costs are so dependent on materials cost, however, and it is not clear if the prices of lead-acid batteries can be reduced much further. If the price of lead rises to its previous level, then the projected price would rise to over $800/kWe. These figures are based on a production level of 200 MWe/year, but since similar lead-acid batteries are already in production for mostly transportation applications, the utility price may not be a strong function of demand in stationary applications.

In general, the O&M costs of batteries will depend strongly on the extent to which various battery components survive in a highly corrosive environment. These costs are also likely to depend strongly on how the battery is used, e.g., one deep discharge a day versus many shallow discharges. Current estimates indicate that the largest component of the O&M costs for lead-acid batteries will most likely be due to the periodic replacement of the battery stacks every 2,000 to 4,000 cycles (roughly equivalent to 8 to 16 years). Since many parts of the used stacks, such as the lead, are reusable or recyclable, a replacement stack only costs about 50 percent of the original. Assuming the plant operates for 250 five-hour cycles per year, these costs, levelized over a 30-year-plant life, are 6 to 20 mills/kWh.

The costs of the daily maintenance can be greatly reduced by the addition of systems such as an automatic water system to add water to the batteries, and monitors to track chemical concentrations. However, battery housings will have to be cleaned periodically to prevent deposits from developing which could short circuit battery terminal connections. These annual O&M costs are estimated to be about 1 to 4 mills/kWh.

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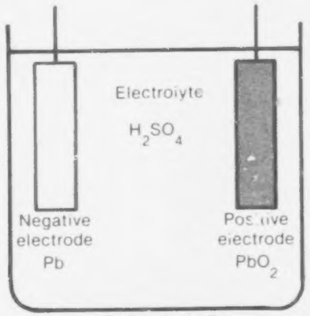
[93] Battery capital costs are best represented in units of kilowatt-hour not kilowatt-electric. However, to be consistent with the other technologies considered here, we will use this latter measure. To convert kilowatt-electric to kilowatt-hour, divide the former by 5 (assuming a five-hour discharge period).

Figure 4-32.—Lead-Acid Batteries

The illustrations below show how a lead-acid battery stores electric energy. Advanced lead-acid batteries differ in the construction of the electrodes, etc., but the basic operation is the same as the more traditional designs.

In its fully *charged* state, the negative electrode consists of spongy lead with a small mixture of antimony (around 10 percent), while the positive electrode is lead dioxide. The electrolyte is sulfuric acid.

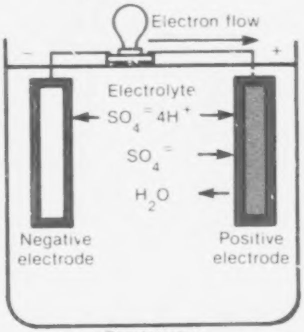

Electrolyte
H_2SO_4
Negative electrode
Pb
Positive electrode
PbO_2

Fully charged

As the battery *discharges*, the lead in the negative electrode reacts with sulfate ions in the electrolyte to form lead sulfate and release two electrons. At the positive electrode, these electrons combine with the lead dioxide in the electrode, and four hydrogen ions and a sulfate ion from the electrolyte to form lead sulfate and water.

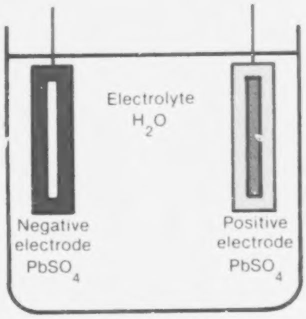
Negative electrode: $pb + SO_4^{=} \rightarrow PbSO_4 + 2e^-$

Positive electrode: $PbO_2 + 4H^+ + SO_4^{=} + 2e^- \rightarrow PbSO_4 + 2H_2O$


Electron flow
–
+
Electrolyte
$SO_4^{=}\ 4H^+$
$SO_4^{=}$
H_2O
Negative electrode
Positive electrode

Discharging

When fully *discharged*, the battery's electrodes are almost entirely lead sulfate and the electrolyte is largely water.

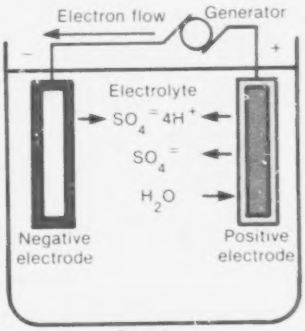

Electrolyte
H_2O
Negative electrode
$PbSO_4$
Positive electrode
$PbSO_4$

– Discharged

To *charge* the battery, electrons are driven back into the negative electrode, where they combine with the lead sulfate to form lead, which remains on the electrode, and sulfate ions, which are released into the electrolyte. At the positive electrode, the lead sulfate combines with water molecules to form lead dioxide, which stays on the electrode, hydrogen and sulfate ions which are released into the electrolyte, and two electrons, which are driven by the charging generator to the negative electrode.

Negative electrode: $PbSO_4 + 2e^- \rightarrow Pb + SO_4^{=}$

Positive electrode: $PbSO_4 + 2H_4O \rightarrow PbO_2 + 4H^+ + SO_4^{=} + 2e^-$


Electron flow
Generator
–
+
Electrolyte
$SO_4^{=}\ 4H^+$
$SO_4^{=}$
H_2O
Negative electrode
Positive electrode

Charging

SOURCE: *The Encyclopedia Americana*, International Edition (Danbury, CT: Encyclopedia Americana Corp., 1980), vol. 3, p. 360.

The safety hazards of advanced lead-acid batteries occur primarily if the battery is overcharged. In this instance, it will generate potentially explosive mixtures of hydrogen and oxygen which must be ventilated. Stibine and arsine can also be formed from the materials used in the electrodes. Finally, there are also dangers from acid spills and fire. When the battery is decommissioned, the lead must be recycled, and the acid disposed of. However, there is much experience with lead-acid batteries, and few safety problems are anticipated if well-established maintenance and safety procedures are followed.

Zinc-Chloride Batteries.—The zinc-chloride battery has been under development since the early 1970s. It is a flowing electrolyte battery (see figure 4-33). During charging, zinc is removed from the zinc-chloride electrolyte and deposited onto the negative graphite electrode in the battery stack, while chlorine gas is formed at the positive electrode. The gas is pumped into the battery sump where it reacts with water at 10° C to form chlorine hydrate, an easily managable slush. During discharge, the chlorine hydrate is heated to extract the chlorine gas, which is pumped back into the stack, where it absorbs the zinc and releases the stored electrical energy.

A principal advantage of the zinc-chloride battery is that it promises to be ultimately less expensive than the lead-acid battery, due primarily to the inexpensive materials that go into its construction. However, the technology, which requires pumps and refrigeration equipment, is more complex—it is sometimes described as being more like a chemical plant than a battery.[94] Since no commercial design zinc-chloride battery has yet been operated, any cost projections must be taken with some caution. (See appendix A, table A-9.)

Estimates indicate that at a production level of about 700 MWe/year, zinc-chloride batteries could be sold at a price less than $500/kWe. Because zinc-chloride batteries will most likely make their first appearance in grid-connected use (unlike lead-acid batteries which are already sold in other markets), this price is likely to depend strongly on the volume produced. If only 50 MWe/year were made, the price could be about $860/kWe; and early commercial units could cost as much as $3,000/kWe.

The zinc-chlorine battery may have a longer lifetime than the lead-acid battery. The best cells have run for 2,500 cycles, and while there have been numerous problems with pumps and plumbing, no basic mechanisms have been identified which would limit the lifetime to less than 5,000 cycles.[95] However, the 500 kWh test module at the BEST facility has only run for less than 60 cycles, and several tough engineering problems have yet to be overcome before the battery can have a guaranteed lifetime long enough for commercialization. In addition, the AC to AC roundtrip efficiency, which is currently in the low 60 to 65 percent range for the large battery systems, must be increased to 67 to 70 percent; values in this range have been attained by smaller prototypes.

The O&M requirements of zinc-chloride systems are even more uncertain than for lead-acid systems. However, the expected longer lifetimes, and the less expensive replacement costs for the stacks and sumps (estimated to be about one-third the initial capital cost of the battery) should lead to levelized replacement O&M costs in the 3 to 9 mills/kWh range. For lack of better data on operating experience, the annual O&M costs are estimated to be the same as for lead-acid, 1 to 4 mills/kWh, though because of the increased complexity of the system, they probably will be higher.

Another major advantage of the zinc-chloride battery over the lead-acid battery is that their reaction rates are controllable. This is due to the fact that, in a charged zinc-chloride battery, the zinc and the chlorine are separated in the stacks and sumps. The rate at which the battery discharges is controlled by the speed at which the pumps allow the reactants to recombine. This not only makes the battery more flexible in its operation, but provides a major safety advantage in that if a zinc-chloride cell malfunctions, its discharge can be stopped by shutting off the chlorine pumps. In contrast, the reactants in a

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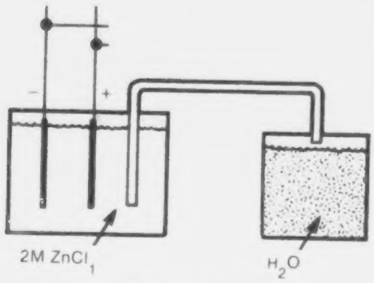
[94] OTA staff interviews with (1) Arnold Fickett, op. cit., 1984 and (2) J.J. Kelley, EXIDE Corp., Aug. 29, 1984.

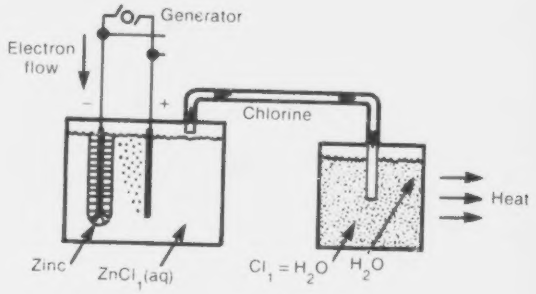
[95] OTA staff interview with Arnold Fickett, op. cit., 1984.

Figure 4-33.—Zinc-Chloride Flowing Electrolyte Batteries



Fully discharged

In its fully *discharged* state, the electrolyte in the battery stack consists of a concentrated solution of zinc chloride. The graphite negative electrode and the graphite or ruthenia-catalyzed porous titanium positive electrode are inert. The battery sump contains water.



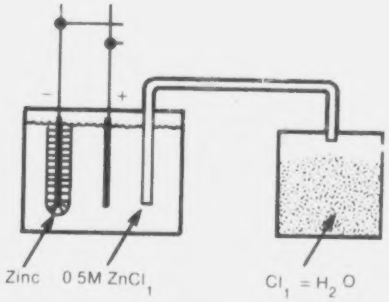
Charging

As the battery is *charged*, chlorine ions from the electrolyte combine at the positive electrode to form chlorine gas and release two electrons. These electrons are driven to the negative electrode by the charging generator. There they combine with zinc being plated onto the negative electrode. The chlorine gas is pumped to the sump which has been chilled to below 10°C. The gas reacts with the cold water and forms an easily storable solid, chlorine hydrate.

Negative electrode: $Zn^+ + e^- \rightarrow Zn$

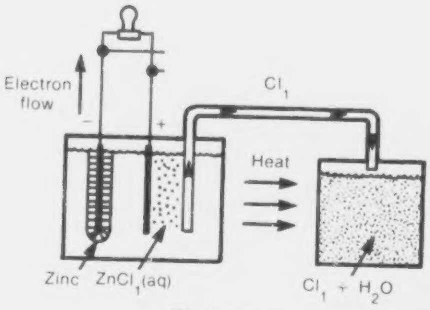
Positive electrode: $2\ Cl' \rightarrow Cl_2 + 2e^-$

Sump: Cl_2(aqueous) $+ xH_2O \rightarrow Cl_2 = xH_2O$ (solid)



Fully charged

When the battery is fully *charged*, the negative electrode is plated with zinc and the electrolyte has only a weak concentration of zinc chloride. The battery sump is filled with chilled chlorine hydrate.



Discharge

The battery is *discharged* by heating the chloride hydrate in the sump, which then releases the chlorine gas. This gas is pumped to the stack, where it combines with electrons from the positive electrodes and breaks into chlorine ions. At the negative electrode the zinc atoms release electrons and enter the electrolyte as zinc ions.

Negative electrode: $Zn \rightarrow Zn^+ + e^-$

Positive electrode: $Cl_2 + 2e^- \rightarrow 2\ Cl^-$

Sump: $Cl_2 + xH_2O$ (solid) $\rightarrow Cl_2$(gas) $+ xH_2O$

SOURCE: Energy Development Associates, *Development of the Zinc-Chloride Battery for Utility Applications* (Palo Alto, CA: Electric Power Research Institute, June 1983), EPRI EM-3136.

charged lead-acid battery cell remain in the same battery case, so that short-circuited terminals could lead to a sudden release of the stored energy.

A major concern of regulatory officials considering zinc-chloride plants is likely to be the safety problems associated with the accidental release of chlorine. Since the chlorine is stored in a solid form, there is no danger of a sudden release of large quantities of the gas. However, the same procedures used in industrial plants manufacturing or using this gas must be followed. In addition, the sumps must be sufficiently insulated so that in the event of a malfunction of the refrigeration system, the chlorine will stay frozen in the chloride hydrate phase long enough for repairs to be made.

SUMMARY OF CURRENT ACTIVITY

The tables in appendix A at the end of this report summarize the cost and performance characteristics discussed in this chapter. Table 4-2 summarizes the information detailed in the appendix. Table 4-4 provides an overview of the plants which currently are installed or operating in the United States. The extent to which capacity already has been deployed or is being constructed provides an additional indication of the cost, performance and risk associated with the technologies.

Table 4-4.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985

Technology	Capacity	Location	Primary sources of funds	Status
Wind turbines[a]	550+ MWe (gross)[b]	California wind farms	Nonutility	Installed
	100+ MWe (gross)[c]	U.S. wind farms outside of California	Nonutility	Installed
	? MWe[d]	All U.S. wind farms	Nonutility	Under construction (1986)
Solar thermal electric:				
Central receiver	10 MWe (net)[e]	Daggett, CA	Utility, nonutility, and Government	Installed
	0.75 MWe	Albuquerque, NM	Utility, nonutility, and Government	Installed
Parabolic trough	14 MWe (net)	Daggett, CA	Nonutility	Installed
	30 MWe (net)	Daggett, CA	Nonutility	Under construction (1986)
Parabolic dish	0.025 MWe (net)[f]	Palm Springs, CA	Government	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Under construction
	3.6 MWe	Warner Springs, CA	Nonutility	Installed
Solar pond	None			
Photovoltaics:				
Flat plate	1 MWe (dc, gross)	Sacramento	Utility and Government	Installed
	1 MWe (dc, gross)	Sacramento, CA	Utility and Government	Under construction (1985)
	1 MWe (dc, gross)	Hesperia, CA	Nonutility	Installed
	6.5 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Installed
	0.75 MWe (dc, gross)	Carrisa Plains, CA	Nonutility	Under construction
Concentrator	4.5 MWe (dc, gross)	Borrego Springs, CA	Nonutility	Installed[g]
	1.5 MWe (dc, gross)	Davis, CA	Nonutility	Installed[g]
	3.5 MWe (dc, gross)	Barstow, CA	Nonutility	Installed[g]
Geothermal:				
Dual flash	10 MWe	Brawley, CA	Utility/nonutility	Installed
	10 MWe	Salton Sea, CA	Utility/nonutility	Installed
	47 MWe (net)	Heber, CA	Nonutility	Under construction (1985)
	32 MWe (net)	Salton Sea, CA	Nonutility	Under construction (1985)
Binary:				
Small	2 × 3.5 MWe	Mammoth, CA	Nonutility	Installed
	3 × 0.3 MWe	Hammersly Canyon, OR	Nonutility	Installed
	3 × 0.4 MWe	Hammersly Canyon, OR	Nonutility	Installed[h]
	10 MWe	East Mesa, CA	Nonutility	Installed
	1 × 0.75 MWe (gross)	Wabuska, NV	Nonutility	Installed
	3 × 0.35 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	3 × 0.45 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	4 × 1.25 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
	3 × 0.85 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
Large	45 MWe (net)	Heber, CA	Utility, nonutility, and Government	Installed

Table 4-4.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985—Continued

Technology	Capacity	Location	Primary sources of funds	Status
Fuel cells:				
Large	None			
Small[j]	38 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Installed
Small[j]	5 × 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Under construction
Fluidized-bed combustors:				
Large grass roots	160 MWe	Paducah,KY	Utility[k] and Government	Under construction (1989)
Large retrofit	100 MWe	Nucla, CO	Utility[k]	Under construction (1987)
	125 MWe	Burnsville, MN	Utility[k]	Under construction (1986)
	125 MWe	Brookesville, FL	Nonutility	Under construction (1986)
Small cogeneration	30 MWe	Colton, CA	Nonutility	Under construction (1985)
	25 MWe	Fort Wayne, IN	Nonutility	Under construction (1986)
	15 MWe	Ione, CA	Nonutility	Under construction (1987)
	67 MWe	Chester, PA	Nonutility	Under construction (1986)
	90 MWe[l]	Decatur, IL	Nonutility	Under construction (1986)
	50 MWe[m]	Cedar Rapids, IA	Nonutility	Under construction (1987)
	3.5 MWe	Pekin, IL	Nonutility and Government	Installed
	28 MWe	Pontiac, MI	Nonutility	Under construction (1986)
	2.8 MWe	Washington, DC	Nonutility and Government	Installed
	24 MWe	Enfield, ME	Nonutility	Under construction (1986)
	20 MWe	Chinese Station, CA	Nonutility	Under construction (1986)
IGCC[n]	100 MWe	Daggett, CA	Utility, nonutility, and Government	Installed
Batteries:				
Lead acid[o]	0.5 MWe	Newark, NJ	Utility and Government	Installed
Zinc chloride	None[p]			
CAES:				
Mini	None			
Maxi	None			

[a] Includes small- and medium-sized wind turbines.

[b] Approximately 550 MWe were operating in California at the end of 1984. It is not known how much additional capacity was installed by May 1985.

[c] Approximately 100 MWe were operating outside of California at the end of 1984. It is not known how much additional capacity had been installed outside California by May 1985.

[d] It is not known how much capacity was under construction on May 1, 1985.

[e] This facility, the Solar One Pilot plant, is not a commercial-scale plant and differs in other important ways from the type of system which might be deployed commercially in the 1990s.

[f] This installation consists of only one electricity producing module; a commercial installation probably would consist of hundreds of modules.

[g] Only 10 percent of the modules were operating at the time because of problems with the power conversion systems.

[h] Installed but not operating, pending contractural negotiations with utilities.

[i] The equipment modules have been delivered to the site; site preparation, however, has not started.

[j] These units are not commercial-scale units.

[k] Including the Electric Power Research Institute.

[l] This is the total capacity which may be generated from the four AFBC boilers which will be installed.

[m] This is the total capacity which may be generated from the two AFBC boilers which will be installed.

[n] While this installation, the Cool Water unit, uses commercial-scale components, the installation itself is not a commercial-scale installation.

[o] While this installation at the Battery Energy Storage Test Facility uses a commercial-scale battery module, the installation itself is not a commercial-scale installation.

[p] A 0.5-MWe zinc chloride commercial-scale battery module was, however, operating at the Battery Energy Storage Test facility until early 1985.

SOURCE: Office of Technology Assessment.

Chapter 5

Conventional Technologies for Electric Utilities in the 1990s

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Chapter 5

Conventional Technologies for Electric Utilities in the 1990s

INTRODUCTION

The financial difficulties faced by utilities in the 1970s and early 1980s have prompted many to investigate extending the lives of existing facilites or even rehabilitating old plants to yield additional capacity. Control of electricity end use has also surfaced as another promising alternative to meeting all or part of future load growth. For most of these utilities, however, conventional central station powerplants still provide the base against which all other supply-enhancing or demand-controlling investments are compared.

This chapter presents a benchmark set of cost and performance estimates for conventional options of traditional central station powerplants and for a variety of options which extend the lives or otherwise improve the performance of existing generating facilities. Since these strategic options are not the principal focus of this assessment, these estimates are presented primarily to enable comparisons with the new generating options discussed in chapter 4. These comparisons are reported in chapter 8. In addition, load management, one of the strategic options being pursued agressively by utilities in many regions of the United States for controlling end use of electricity, is discussed in this chapter.

PLANT IMPROVEMENT AND LIFE EXTENSION

Introduction

In the wake of declining demand growth and soaring costs of new generating capacity, many utilities have begun to examine the so-called **plant betterment** option for improving the performance of or extending the lives of existing capacity.[1] This option is likely to become increasingly important through the end of this decade and into the 1990s—a period when the U.S. powerplant inventory will undergo dramatic changes. For example, since 1975, new plant order cancellations nationwide by utilities have exceeded new plant orders. By the year 1995, if present new plant ordering patterns continue about a third of the existing fossil steam generating capacity in the United States will be more than 30 years old (see figure 5-1 and table 5-1). The age distribution varies considerably by region, however, as discussed in chapter 7. Moreover, the plants "coming of age" during this period will be considerably more valuable than those of early vintages. In the 1950s, unit sizes grew to over 100 MW and heat rates fell to below 10,000 Btu/kWh while older units (1920s and 1930s vintage) were much smaller with heat rates of as high as 20,000 Btu/kWh.[2] While in the past, the benefits of new technology far outweighed plant betterment options, because of the relative quality of currently existing plants, this situation is rapidly changing.

Traditionally, investments in aging fossil plants began to decline after about 25 years causing reliability to deteriorate accordingly. The plants were relegated to periodic operation, reserve duty, and, finally, demolition. For the remainder

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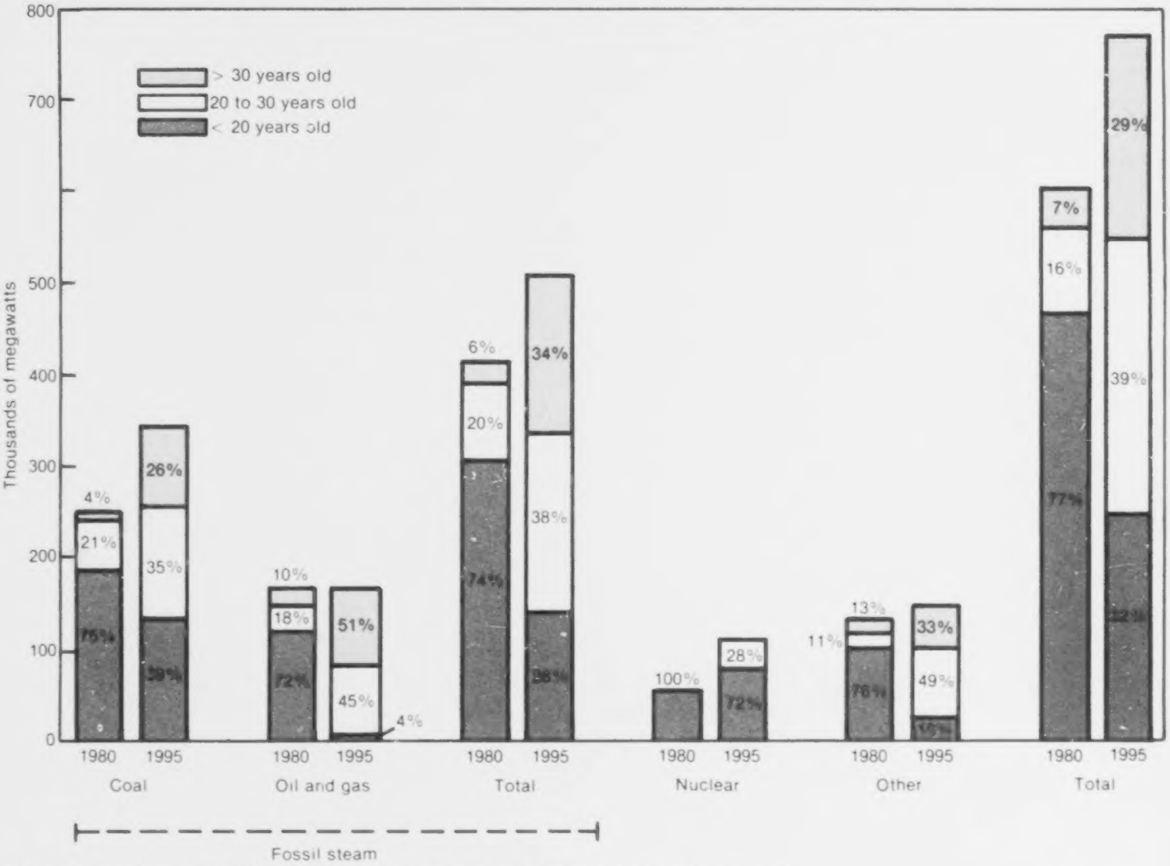
[1] R. C. Rittenhouse, "Maintenance and Upgrading Inject New Life Into Power Plants," *Power Engineering*, March 1984, pp. 41-50; T. Yezerski, Pennsylvania Electric Association Power Generation Committee, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co.," unpublished paper, Sept. 18, 1984; R. Carelock, Potomac Electric Power Co., "Plant Life Extension: Potomac River Generating Station," unpublished paper, September 1984.

[2] R. Smock, "Can the Utility Industry Find a Fountain of Youth for Its Aging Generating Capacity?" *Electric Light and Power*, March 1984, pp. 14ff.

Figure 5-1.—Age of U.S. Electric Power Generating Facilities, 1980-95



SOURCE: Office of Technology Assessment; prepared from data provided by E. H. Pechan & Associates, 1984.

Table 5-1.—Average and Weighted Average Age of U.S. Electric Power Generating Facilities, 1984

Type of unit	Number of units	Total capacity (MW)	Average age (years)	Weighted[a] average age (years)
Coal steam	1,352	255,197	23.6	13.2
Oil steam	794	99,175	28.9	17.9
Gas steam	823	63,708	27.4	17.4
Lignite steam	38	11,382	16.9	5.9
Nuclear	91	72,736	7.2	5.8
Combined cycle	86	6,788	8.8	7.5
Oil peaking	839	31,199	11.2	10.2
Gas peaking	208	6,453	11.7	9.7
Internal combustion	2,302	3,922	27.2	22.1
Hydro	2,642	64,788	45.7	24.1
Pumped hydro	130	14,436	11.4	8.1

[a] Weighted by installed generating capacity in megawatts.

SOURCE: Robert Smock, "Can the Utility Industry Find a Fountain of Youth for Its Aging Generating Capacity?" *Electric Light and Power*, March 1984, pp. 13-17.

of this decade, as new nuclear base load plants come on-line, existing base load fossil units will increasingly be relegated to cycling duty which can significantly shorten plant life. Recent studies, however, show that in many cases, such plants, at least those built in the 1950s and 1960s, can be refurbished cost effectively for $200 to $400/kW, even in cycling duty applications.[3] These studies also indicate that some refurbishment projects can include efficiency improvements, and capacity upgrades of 5 to 10 percent.[4]

Finally, many siting and environmental requirements facing new capacity can be avoided by rebuilding existing capacity. Table 5-2 shows the marked contrast in these requirements for new versus existing coal-fired units. Current Federal regulations (New Source Performance Standards—NSPS) require that any unit that is more than 50 percent rebuilt (defined as 50 percent of the cost of a new boiler) must reduce sulfur dioxide emissions by 90 percent of the uncontrolled level. It turns out that a great deal of plant betterment can be accomplished under this 50 percent requirement. Moreover, an important consideration with this requirement is that the emissions reduction strategy for the unit must be "practical."[5] Utilities assert, in some cases, that if the NSPS requirement were applied, life extension and plant betterment options would not be practical, i.e., cost effective, because scrubber backfits would be necessary.[6] We discuss these considerations later.

Objectives of Plant Betterment Options

It is important to note that plant betterment is only a substitute for new capacity to the extent plant retirement can be deferred past the time originally scheduled, and the plant's capacity can be increased as a result of betterment. When these conditions prevail, plant betterment options offer considerable promise[7] relative to other strategic options. However, they present a complicated planning problem for utilities. Indeed, a considerable investment is often required to develop the details of a prospective project and its expected cost. For example, in 1984 Wisconsin Electric Power Co. commissioned detailed plant

Table 5-2.—Environmental Requirements for Existing and New Plants

Particulate	Air emissions SO_2	NO_x	Condenser cooling water	Ash disposal	Wastewater treatment
Existing plants (1980 typical plants):					
Varies from 0.12 to 0.25 lb/MMBtu	3.2 lb/MMBtu. Compliance based on coal analysis	1.3 lb/MMBtu. No monitoring required	Thermal limits based on ecological studies	Sluicing and ponding of combined fly and bottom ash	Combining waste streams (coal pile, broiler cleaning, etc.) for cotreatment in ash pond
New plants >73 MW:					
0.03 lb/MMBtu 20% opacity Requires baghouse or very efficient electrostatic precipitator	1.2 lb/MMBtu and 90% reduction except 70% if emission <0.06 lb/MMBtu. Compliance based on continuous monitors. Requires coal cleaning or wet scrubber (total capital = $248/kW)	0.6 lb/MMBtu and 65% reduction. Compliance based on continuous monitors	Cooling towers	Dry collection and reuse or landfilling of flyash. Sluicing and ponding of reuse of bottom ash	Dedicated possible separate treatment pond(s) may require artificial liner(s) and chemical addition

SOURCE: W. Parker, "Plant Life Extension—An Economic Recycle," *Power Engineering*, July 1984; and Judi Greenwald, U.S. Environmental Protection Agency, personal correspondence with OTA staff, June 18, 1985.

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[3] Gibbs & Hill, Inc., "Considerations for Power Plant Life Extension: Prospects for the 1990s," contractor report to OTA, October 1984.

[4] R. Smock, "Operating Unit Heat Rates Can Be Cut, Says EPRI; New Units Can Be 10 Percent More Efficient," *Electric Light and Power*, March 1984, p. 24.

[5] The regulation reads that an existing facility falls under theses guidelines provided "it is technologically and economically feasible to meet the applicable standards set forth in this part."

[6] "Power Plant Life Extension Economics, Plans Explored at American Power Conference," *Electric Light and Power*, June 1984, pp. 27-30.

[7] One indication that this promise is already being realized is that average plant availability of existing units in the United States has increased from 67 percent in 1977 to 76 percent in 1984, partially as a result of plant betterment activities.

betterment studies on a number of existing fossil units, at a cost of more than $1 million per study.

In considering plant betterment or life extension programs, utilities need to account for both system level objectives, such as coordination with existing capacity expansion and scheduled maintenance plans, and unit level objectives, such as extending the life for a target number of years at a specified level of capacity, efficiency, and availability. Indeed, the overall characteristics of a utility's system dictate the timing and level of investment justified in a particular betterment/life extension project. For example, a utility with a high reserve margin may consider the relatively simple step of derating an aging unit to lengthen its life, while a utility with a low reserve margin may consider upgrading the unit to both extend its life and increase its capacity. Although the age of the unit and the production lost during rebuilding may make the latter strategy more costly than life extension alone, usually it is still much less expensive than building new capacity.

Ultimately, all individual improvements relate to either increased productivity or longevity. **Productivity improvements** involve increased efficiency; increases (restoration or upgrading) in rated capacity; reduced fuel costs (e.g., through fuel switching); reduced labor requirements; increased capacity factors; and reduced emissions. **Longevity improvements** include mechanisms for increasing plant life at specified levels of rated capacity. This may mean extending the life of a unit at full rated capacity or, by contrast, "mothballing" the unit for use at a later time when all or part of the rated capacity is needed; mothballing is sometimes referred to as an extended cold shutdown.

Virtually all life extension/plant improvement programs begin with a detailed performance test of any candidate plant to determine the current status of the equipment, i.e., how far the current plant operating parameters are from the original design specifications. Equipment evaluated in the performance test includes the turbine generator, boiler, condenser, feedwater heaters, auxiliary equipment systems, flue gas cleaning equipment, and plant instrumentation. Comparison of the most recent performance test with historical performance identifies areas to be investigated in more detail. A detailed examination of the boiler usually precedes other studies since its results are likely to control the length of the overall plant betterment project being considered. Also, other areas of the overall study may be affected if, for example, the boiler analysis reveals that it must be operated at lower pressure to lengthen its life.[8]

Recommendations resulting from a detailed performance test and analysis, sometimes termed a design change package (DCP),[9] generally fall into two categories: 1) new procedures for startup, operations and maintenance, training of personnel, update of performance records, and spare parts support; and 2) equipment or component modifications. The category (1) improvements are usually relatively low cost and very cost effective. The nature of the category (2) improvements depends on the age of the equipment and the facility.

Likely plant betterment candidates are middle-age generating units (10 to 20 years old) which, at some point in their lives, are usually relegated to intermediate duty cycling where they experience greater load changes, and more frequent starting and stopping. As noted earlier, this change in operation can significantly reduce the operating life of the unit and, as a result, upgrading of middle age units often means adapting them for cycling duty. Typical enhancements include full flow lubricating oil systems, automatic turbine controls, and thermal and generator performance monitors (newer units will also benefit from these improvements). In addition, the middle-aged units will benefit from turbine modification and temperature control equipment.

Upgrading or life extension of older units (20 years or more) usually requires evaluating the replacement of major components such as turbine rotors, shells, and generator coils. While uprating of components, such as the turbine, may be possible for older units, it is usually a highly customized job. Table 5-3 shows a typical turbine generator uprating checklist which gives the possible limitations on a candidate upgrading program. Figure 5-2 shows the possible improvements in heat rate of an upgraded (uprated and restored) turbine-generator unit.

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[8] S. J. Schebler and R. B. Dean, Stanley Consultants, "Fossil Power Plant Betterment," paper presented at Edison Electric Institute Prime Movers Committee Meeting, New Orleans, LA, Feb. 1, 1984.

[9] W. O'Keefe, "Planning Helps Make Plant Improvements More Effective," *Power*, February 1984, pp. 89-90.

The complexity of performance testing and analysis has prompted the major equipment manufacturers to offer comprehensive plant modernization programs.[10] Both manufacturers and architect-engineering firms see plant betterment projects as a promising market for their goods and services.

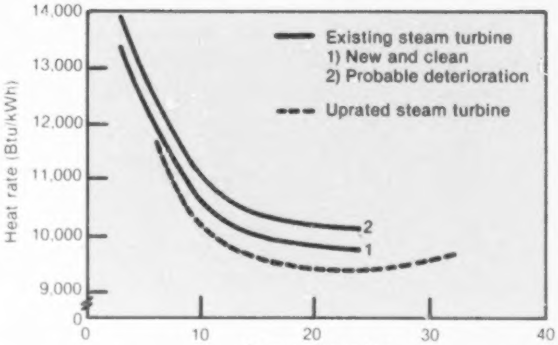
Finally, some plant improvement projects may be aimed at reducing emission levels or the use of specific fuels. For example, many projects in recent years have been carried out to convert oil-fired capacity to coal. Such conversions often involve unit derating, but recent studies show that recovering as much as two-thirds of the capacity lost after coal conversion can be achieved at 40 to 50 percent of the dollars per kilowatt coal conversion cost.[11]

Table 5-3.—Turbine Generator Uprating Checklist

1. Additional plant steaming capability:
   - Boiler flow, pressure, and temperature
   - Condenser flow and vacuum
   - Feedwater heater train pressures and flow
2. Additional electrical capability:
   - Breakers
   - Distribution system
   - Protective devices
3. Generator capability:
   - Field and armature temperatures
   - Actual cooling water temperature
   - Present condition
   - Exciter capability
4. Turbine uprating capability:
   - Casing limitations
   - Exhaust bucket limitations
   - Modification packaging
5. Uprating effects on system efficiency:
   - Design improvements
   - Restorations effects
   - Part load effects

SOURCE: T. Yezerski, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co.," briefing presented to Pennsylvania Electric Association Power Generation Committee, Hershey, PA, Sept. 18, 1984.

Figure 5-2.—Heat Rate v. Generator Output for Uprated and Restored Turbine-Generator Set



SOURCE: Westinghouse Electric Corp., "Power Plant Life Extension, Renovation & Uprating Workshop," presented to American Public Power Association, Omaha, NB, May 22-24, 1984.

Relative Cost and Performance

The principal effects of fossil powerplant aging are: 1) decreased efficiency, i.e., the amount of electricity generated per Btu declines as plant heat rate increases, and 2) more and longer forced outages. Figure 5-3 shows the rate of increase in heat rate as a function of age for a typical fossil plant; the average is about 0.3 percent per year with average maintenance practices.[12] After about 20 years, the reliability of typical plants declines dramatically; figures 5-4 and 5-5 show typical increases in rate and duration of forced outages as a function of age.

Utility concern about reliability, in particular, prompts the decision to invest in plant betterment projects because the cost of lost production during an outage may be very high. For example, if a utility's replacement power cost $0.04/kWh, a 1 percent improvement in the capacity factor of a 500 MW fossil unit will save the utility about $1.75 million a year. That savings must, of course, be balanced against the cost of achieving the capacity factor improvement; this trade-off is the central focus of plant betterment studies. The trade-off is illustrated in figure 5-6; the total "reliability cost" of operating a generating facility is the sum of the cost of lost production when outages occur and the plant betterment investment (or

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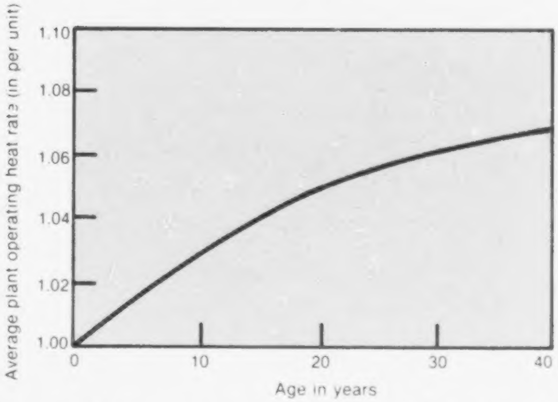
[10] For example, Westinghouse has been marketing turbine-generator upgrades for several years.

[11] P. Miliaras, et al., "Reclaiming Lost Capability in Power Plant Coal Conversions: An Innovative Low-Cost Approach," *Proceedings of the Joint Power Conference*, American Society of Mechanical Engineers, 1983, 83-JPGC-Pwr.

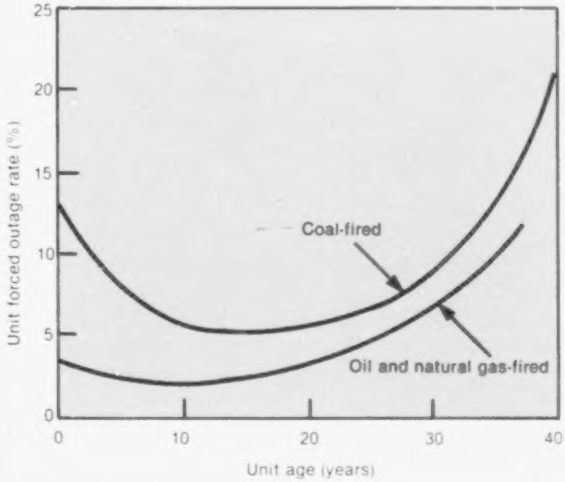
[12] H. Stoll, General Electric Co., "The Economics of Power Plant Upgrading," unpublished paper, May 22, 1984.

Figure 5-3.—Trend of Powerplant Heat Rate With Age



SOURCE: J. Studniarz, "Upgrading Fossil Steam Turbine Generators," General Electric Co., unpublished paper, 1984.

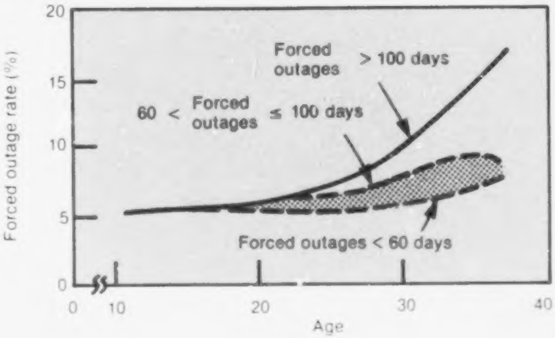
Figure 5-4.—Trends of Forced Outage Rates With Age[a]



[a]Fossil-fired 50 to 200 MW units.

SOURCE: H. G. Stoll, "The Economics of Power Plant Upgrading," paper presented at the Power Plant Life Extension, Renovation, and Uprating Workshop, American Public Power Association, Omaha, NB, May 22, 1984.

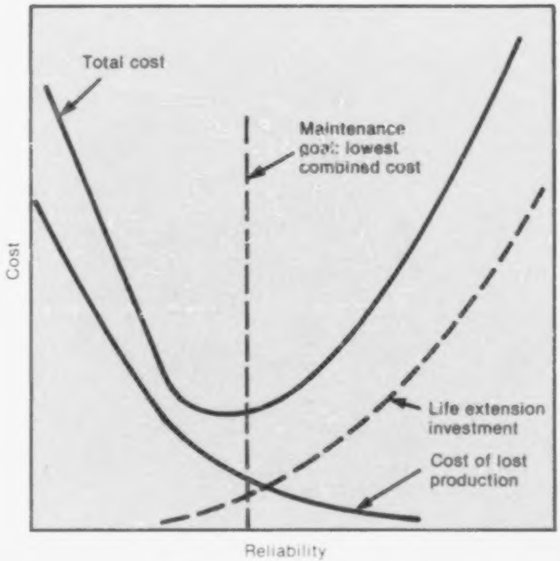
Figure 5-5.—Trend of Plant Forced Outage Rate Duration With Age[a]



[a]Powerplant forced outage rate trends by annual forced outage hour contributions for coal-fired units 50 to 200 MW.

SOURCE: H. G. Stoll, "The Economics of Power Plant Upgrading," paper presented at the Power Plant Life Extension, Renovation, and Uprating Workshop, American Public Power Association, Omaha, NB, May 22, 1984.

Figure 5-6.—Life Extension Cost v. Powerplant Reliability



SOURCE: Adapted from R. C. Rittenhouse, "Maintenance and Upgrading Inject New Life into Power Plants," *Power Engineering*, March 1984.

preventative maintenance allowance) charged to the plant to establish a given level of reliability. The cost of outage decreases as reliability increases and the plant betterment investment increases. The target of a plant betterment program is to minimize the total cost as shown in the figure.

The life extension and/or upgrading decision is complicated by the fact that, while a powerplant's forced outage rate increases with age, the aging characteristics of individual plant components as well as the cost of improving component reliability may vary widely.

Regulatory and Insurance Considerations

Regulation of Plant Betterment Projects

In addition to engineering feasibility, compliance with over 50 Federal and State regulations may be required in the course of considering a plant betterment program.[13] These include Federal and State air quality programs, water quality and solid waste programs, environmental impact studies, Corps of Engineer rules, exemptions from the Powerplant and Industrial Fuel Use Act, and utility commission approval—see table 5-4.

Perhaps the most important regulatory considerations are the major Federal air quality regulations of NSPS, mentioned earlier, and the Prevention of Significant Deterioration (PSD) rules. Generally, Federal regulations apply to a plant betterment program that increases emissions by any amount or costs more than 50 percent of a new boiler. State Implementation Plans and other State air quality statutes will generally apply to all projects.

Of particular concern may be the NSPS requirements which require that, if a fossil plant (>250 MMBtu/hr and constructed prior to 1971) is either "modified" or "reconstructed" as defined in table 5-4, the plant is subject to the 1978 NSPS provisions of stringent emissions limitations and percent sulfur removal. This would in most instances require pollution controls on a facility where few, if any, existed prior to the modification. The requirements are even more stringent for plants constructed between 1971 and 1978. It is important to note, however, that under the current regulations a great deal of plant betterment can be and is already being accomplished without these provisions being invoked.

Table 5-4.—Powerplant Life Extension Projects: Regulatory Summary

Federal requirements:

NSPS (air):
- Standards apply if facility is:
  1. new:
     —replacement of boiler
  2. modified:
     —physical or operational change that results in increased emissions.
  3. reconstructed:
     —fixed capital costs exceed 50% of the cost of a new steam generator.

PSD (air):
- Permit requirements apply to "major modification"—modification for which net emissions increase exceeds de minimis limits (permit may be issued by State).

NPDES (water):
- Permit required for point source discharges to navigable waterways. Modified sources require new or modified permit (permit may be issued by State).

State requirements:

Air:
- New or modified construction and operating permits required.
- Bubble policy may apply.

Water:
- New or modified construction and operating permits required.

Solid waste:
- New or modified construction and operating permits required.

Other requirements:

EIS:
- Not required unless major renovation subject to Federal licensing occurs.

Corps of Engineers:
- Nationwide permits for construction activity in navigable waters are available.

State PUC:
- Approval required for modification of powerplant and recovery of costs through rate base.

SOURCE: T. Evans, "Regulatory Considerations of Life Extension Projects," Virginia Electric Power Co., unpublished report, 1984.

A PSD permit is also required for any major modification to an existing plant; a special set of provisions defines and is applied to such modifications. Finally, if an upgraded existing facility increases emissions in a nonattainment area, pollution offsets would be required.

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[13] D. Ward and A. Meko, "Regulatory Aspects of Power Plant Betterment," *Workshop Notebook: Fossil Plant Life Extension* (Palo Alto, CA: Electric Power Research Institute, June 1984), EPRI RP-1862-3.

Insurance Considerations

Of some concern in plant betterment projects is how insurance coverage might be affected. Insurance carriers generally consider the nature of risk exposure associated with a modified plant to be different from that of a comparable new facility. When setting insurance coverage premiums, these carriers now initiate very extensive evaluations (and annual reevaluations) of candidate equipment, particularly as more policies are written on a "comprehensive basis" where every piece of equipment is insured."[14] As the power industry moves toward including more plant betterment/life extension in its strategic planning, the implications on insurance coverage will become more important.

Industry Experience

To date, most life extension activity has been confined to planning, but a number of projects have been announced.

Potomac Electric Power Co. (PEPCO) has announced a $79 million project on its Potomac River Station, the oldest in the PEPCO system with two 92 MW and three 110 MW units built between 1949 and 1957. The work will be performed over the next 10 years during each unit's annual 2-month scheduled outage.[15]

Pennsylvania Power & Light Co. (PP&L) is reviewing all fossil and hydroelectric capacity built between 1949 and 1977, comprising about 4,500 MW. The utility has initiated a formal technical inspection program and has identified $173 million worth of individual recommendations.[16] The most important of these is a $20 million project to extend the life of Brunner Island Station (343 MW Unit 1) to 2010.

Wisconsin Power & Light (WEPCO) has commissioned detailed life extension studies at its Port Washington Station (five 80 MW units commissioned between 1935 and 1950) and its Oak Creek Station (eight units totaling 1,670 MW commissioned between 1953 and 1967).

Cincinnati Gas & Electric Co. (CG&E) has decided to commit $2.8 million to its 94 MW Beckjord Unit 1 turbine (currently 29 years old) to permit continued operation through 2013.

Colorado Ute Electric Association, Inc., is completing a major life extension project that includes an atmospheric fluidized-bed (AFBC) boiler retrofit to increase the plant capacity at their Nucla facility from 36 to 110 MW. The project objectives include a 15-percent increase in overall heat rate, a 30-percent reduction in fuel costs, and reduced emissions. The estimated project cost is $840/kW.[17] As mentioned in chapter 4, retrofit applications are likely to be an important entry point to the utility market for AFBC technology.

Duke Power Co., Florida Power Corp., and the Tennessee Valley Authority have all initiated extended cold shutdown programs for a number of units which they plan to reactivate in the early 1990s.

Summary and Conclusions

Plant betterment and life extension of aging fossil units are emerging as economical alternatives to new capacity construction to the extent this can be done, for many utilities. As the industry gains experience with these options, the costs of such activities will become less uncertain. As the U.S. powerplant inventory matures in the late 1990s, plant betterment and life extension are likely to become major components in the portfolio of strategic options of most generating electric utilities.

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[14] F. Mansfield, "A Risk Taker Looks at Utility Equipment Plant Betterment," *Workshop Notebook: Fossil Plant Life Extension* (Palo Alto, CA: Electric Power Research Institute, June 1984), EPRI RP-1862-3.

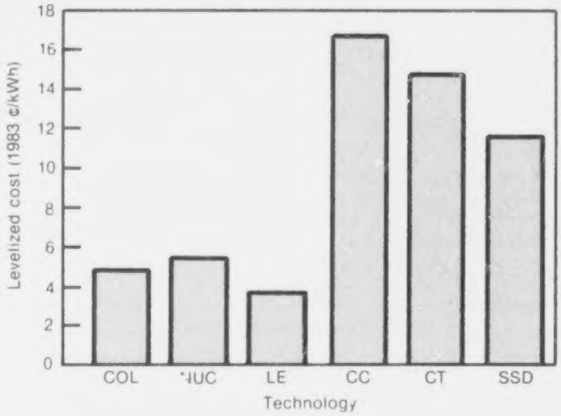
[15] R. Smock, "Operating Unit Heat Rates Can Be Cut, Says EPRI; New Units Can Be 10 Percent More Efficient," op. cit., 1984.

[16] T. Yezerski, "Power Plant Life Extension Practice at Pennsylvania Power & Light Co.," op. cit., 1984.

[17] T. Moore, "Achieving the Promise of FBC," *EPRI Journal*, January/February 1985, pp. 6-15.

CONVENTIONAL GENERATING OPTIONS

Figure 5-7.—Conventional Technology Costs, Utility Ownership—West



Key:
COL — Pulverized coal-fired plants
NUC — Lightwater nuclear powerplants
LE — Life extension existing coal-fired plants
CC — Combined-cycle plants
CT — Combustion turbines
SSD — Slow-speed diesels

SOURCE: Office of Technology Assessment.

In order to be deployed in significant numbers, the developing technologies addressed in this report must compete successfully with existing electric utility generating options. The five major conventional power generation technology types that will most likely be available to electric utilities in the 1990s are: pulverized coal-fired plants, combined-cycle plants, combustion turbines, slow-speed diesels, and light water nuclear powerplants.

This section briefly presents the benchmark cost and performance estimates for these five technologies as well as for life extension of existing coal-fired plants. Cross-technology comparison of these technologies with the developing technologies is contained in chapter 8.

Table 5-5 contains the benchmark set of cost and performance estimates for the five conventional technologies. All of the listed technologies, except one—combustion turbines—are capable of base load operation. Three of these technologies, pulverized coal-fired, combined-cycle, and slow-speed diesel, are also capable of intermediate-load operation. One major difference among the conventional alternatives is plant size. Although there is increasing interest in small, modular plants (see chapter 3), the technologies listed in table 5-5 are generally large, central station powerplants. Slow-speed diesels and combustion turbines represent the smaller sized central station technologies.

The levelized cost model used in chapter 8 was used with the cost and performance estimates shown in table 5-5 to derive most likely electric utility costs. These levelized costs are presented in figure 5-7. This figure also includes a levelized cost estimate for existing coal powerplant betterment. The plant costs and the capacity and efficiency upgrades discussed earlier were applied to the generic coal plant listed in table 5-5 to derive an expected cost for coal plant betterment. According to this figure, the lowest cost conventional alternative is life extension and plant betterment of existing coal units. The next lowest cost conventional alternative is pulverized coal plants, followed by light water nuclear plants.

The cost and performance estimates for the conventional technologies discussed in this section represent the present technologies expected to be available in the 1990s. Additional enhancements to these technologies or different design configurations may occur prior to 1990 which could dramatically change these expected costs.

Table 5-5.—Cost and Performance Summaries

	Technologies					
Reference system	Pulverized coal-fired	Combined-cycle	Combustion turbine	Slow-speed diesel	Municipal solid waste	Nuclear
General:						
Reference year	1990	1990	1990	1990	1990	1990
Reference-plant size	500 MWe	600 MWe	150 MWe	40 MWe	60MWe	1,000 MWe
Lead-time	6-8 years	3-4 years	2-3 years	2 years	5-7 years	11 years
Land required	640 acres	5-10 acres	2-5 acres	10-15 acres	20 acres	1,000 acres
Water required	5.94 million gal/day	2.9 million gal/day	Negligible	Negligible	0.85 million gal/day	10 million gal/day
Performance parameters:						
Operating availability	75%	90%	90%	95%	85%	68%
Duty cycle	Intermediate/ base	Intermediate/ base	Peaking	Intermediate/ base	Base	Base
Capacity factor	25-75%	25-75%	5-15%	25-75%	65-75%	65-75%
Plant lifetime	30 years	30 years	20 years	30 years	20 years	30 years
Plant efficiency	34%	40%	25.0%	39%	20.7%	31.9%
Costs:						
Capital costs	$1,080/kWe	$650/kWe	$350/kWe	$1,200/kWe	$2,500/kWe	$1,700-$2,100/ kWe
O&M costs	9.5 mills/ kWh	2.4-4.2 mills/ kWh	4-4.7 mills/ kWh	5.1-8.2 mills/ kWh	19 mills/ kWh	3-3.3 mills/ kWh
Fuel costs	17 mills/ kWh	30.4 mills/ kWh	48.6 mills/ kWh	42 mills/ kWh	46.9 mills/ kWh	9.1 mills/ kWh

SOURCE: Office of Technology Assessment; complied from Gibbs & Hill, Inc., "Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s," contractor report to OTA, Sept. 13, 1984, and *Technical Assessment Guide* (Palo Alto, CA: Electric Power Research Institute, 1982), EPRI P-2410-SR.

LOAD MANAGEMENT

Introduction

The term *load management* refers to manipulation of customer demand by economic and/or technical means. It involves a combination of economic arrangements and technology typically directed towards one of the following objectives:

1. **Encouraging demand during off-peak periods**: During the valleys of a load curve, a large portion of generating equipment is idle. Utilities benefit when that capacity is more heavily used. This typically is achieved by either shifting use to those periods from peak-demand periods (load shifting) or by encouraging additional use during off-peak periods (valley filling).
2. **Inhibiting demand during peak periods**: It may also be desirable to reduce peak-period demand. When electricity is purchased from other utilities, costs per kilowatt-hour during these periods are high. Or, to meet peak-period demand, a utility may have to use generators which are more costly to operate because they are older and less efficient or they burn more expensive fuel. In addition, if growth in peak-period demand requires the utility to invest in new capacity, load management may reduce the rate at which such expenditures must be made.

In the context of this study, the most important benefit of load management lies in the second objective which if realized allows utilities to defer additional peak-load generating capacity. In addition, by reducing the share of the load served during the peak period, load management permits a higher proportion of demand to be served by lower cost electricity. Other advantages are also becoming evident as utilities gain more experience with load management, and as sophisticated models are developed which permit better assessment of load management.[18] For example, load management may reduce future demand uncertainty. And some utilities have found it to be an effective means of improving the efficiency of power system operation by allowing increased flexibility in the hour-by-hour allocation of system resources.[19]

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[18] For example, see: 1) John L. Levett & Dorothy A. Conant, "Load Management for Transmission and Distribution Deferrel," *Public Utilities Fortnightly*, vol. 115. No. 8, Apr. 18, 1985, pp. 34-39; 2) Associated Power Analysts, Inc., *Study of Effect of Load Management on Generating-System Reliability* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3575.

Load management is only one of many closely related options available to utilities in managing demand. Other *demand management* alternatives include encouraging conversions to electric power through new applications, and more efficient use such as home insulation and electronic motor controls. In addition, demand management is also carried out indirectly to the degree that customers are encouraged to generate their own power. These other demand management options may be pursued independently of load management, or may be implemented as part of an integrated program with load management. Depending on the nature of the demand management strategy, the utility's daily load curve can be modified as shown in figure 5-8.

Within load management falls a very wide range of strategies, technologies, and economic arrangements. These typically center around some combination of: 1) load management incentives, 2) advanced meters, and 3) load control equipment. While many other elements may be present in a load management program, these appear to be of pivotal importance. Although incentives will be touched upon below, the emphasis will be placed on the technologies themselves: specifically advanced meters and load control equipment.

With respect to the number of customers, the residential sector is by far the most important in load management. But the fact that the sector consists of a large number of relatively small consumers makes load management quite difficult to assess and implement. In part, because of this, only a small fraction of the major electric appliances in this sector have load management controls (see table 5-6). Nevertheless, utilities are increasingly interested in residential load management, both because the sector uses a large quantity of electricity (in 1984 it accounted for 34 percent of all electricity used) and because it is the largest contributor to the daily fluctuations in demand (see figure 5-9).

In the industrial and commercial sectors, while only a relatively small number of loads have been managed, the contribution has been significant. These sectors contain major loads amenable to load management, and, compared to the residential sector, fewer customers with larger demands per customer. Hence, load management is already practiced more widely in these sectors. Considerable opportunities remain, however, and industrial and commercial customers likely will continue to account for a major portion of load management during this century.

Current evidence suggests that load management will provide, in many cases, an economic alternative to new generating capacity in the 1990s. It may be a particularly attractive utility investment when it is part of an integrated system designed not only to manage loads but also to serve other utility or customer needs.

Some of the potential for load management can be met by using existing technologies at current costs and performance levels; but considerably greater application will require the introduction of technologies which offer a combination of cost, performance, and risk superior to current technology. Furthermore, institutional arrangements must be developed within which load management can be more easily deployed. Finally, the costs, benefits, and uncertainties of load management options must be better understood and integrated into the thinking of utilities and of others upon whose decisions affect load management deployment.

Major Supply/Demand Variables Relating to Load Management

Key End-Use Sectors and Applications

Central to load management in the 1990s will be the electricity demand patterns which develop in the United States. What sectors will be most important and how will they use electricity? These patterns determine the magnitude of the load at any time, and the shape of the load curve. They

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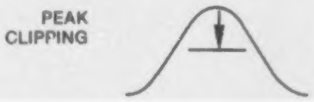
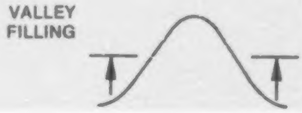
[19] B. F. Hastings, "Cost and Performance of Load Management Technologies," comments presented at OTA Load Management Workshop, Washington, DC, Aug. 15, 1984.

Figure 5-8.—Load Shape Objectives

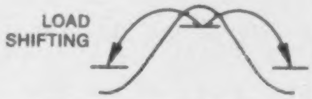
PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.



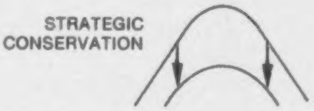
VALLEY FILLING is the second classic form of load management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances decreases the average price. Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.



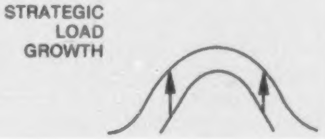
LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. In this case, the load shift from storage devices involves displacing what would have been conventional appliances served by electricity.



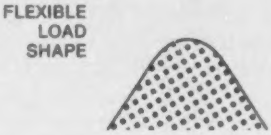
STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end-use consumption. Not normally considered load management, the change reflects a modification of the load shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.



STRATEGIC LOAD GROWTH is the load shape change that refers to a general increase in sales beyond the valley filling described previously. Load growth may involve increased market share of loads that are, or can be, served by competing fuels, as well as area development. In the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise in intensity may be motivated by reduction in the use of fossil fuels and raw materials resulting in improved overall productivity.



FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria he uses is reliability. Load shape can be flexible—if customers are presented with options as to the variations in quality of service that they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable load; concepts of pooled, integrated energy management systems; or individual customer load control devices offering service constraints.



*Adapted from Clark W. Gellings, Highlights of a speech presented to the 1982 Executive Symposium of EEI Customer Service and Marketing Personnel.

SOURCE: Battelle-Columbus Division & Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

Table 5-6.—Use of Major Electricity-Using Appliances in U.S. Residences, 1982

Household characteristics	Total	Census region			
		Northeast	North Central	South	West
Total households (millions)	83.8	18.0	21.3	28.1	16.5
Millions of households where electricity is main:					
Space heating (SH) fuel	13.4	1.3	2.1	6.8	3.1
Water heating (WH) fuel	26.6	3.7	5.5	13.2	4.2
Millions of households where electricity is secondary:					
SH fuel	10.5	1.9	2.1	4.2	2.3
Millions of households with air-conditioning (A/C)	48.7	9.4	12.3	21.3	5.7
Millions of households with combinations of electric:					
SH + WH with A/C	9.0	0.8	1.6	5.4	1.2
SH + WH without A/C	2.9	0.4	0.3	0.8	1.4
Minimum number of controllable points (millions)[a]	88.7	14.4	19.9	41.3	13.0
Points controlled in 1983 (millions)[b]	1.2	0.02	0.44	0.7	0.13
Total 1983 sales of electricity to residential sector (gigawatt hours)	750,948	111,619	184,211	317,458	137,661

[a] This merely is the sum of (number of households with electric space heating as primary source of heating) + (number of households with electric water heaters) + (number of households with air-conditioners).

[b] The figures for the number of points controlled are derived from a 1983 survey of 298 utilities. The results were not broken down by census regions but by EPRI regions, since the EPRI regions do not coincide exactly with the census regions, the figures are approximate. The points itemized here only include water heaters, air-conditioners, and space heaters. These figures include 0.03 million commercial points; because this figure is so small compared to residential points, it does not significantly affect the magnitudes of the numbers.

SOURCES: Office of Technology Assessment, based on data presented in U.S. Department of Energy (DOE), Energy Information Administration (EIA), *Housing Characteristics 1982* (Washington, DC: U.S. Government Printing Office, August 1984), DOE/EIA-031(82); U.S. DOE, EIA, *Electric Power Annual 1983* (Washington, DC: U.S. Government Printing Office, July 1984), DOE/EIA-0348(83); and Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

also strongly influence the selection of load management strategies. For example, managing industrial use of electricity for process heat will be quite different than that of managing residential electricity demand for air-conditioning.

Usage patterns will depend on many interrelated variables; precise predictions of future consumption are impossible.[20] Nevertheless, many useful generalizations can be made by looking at the conditions which have characterized the past.

In the residential sector, the single most important application of electric power is air-conditioning, which in 1984 accounted for about 14 percent of delivered residential electricity.[21] Somewhat less important but still sizable quantities of electricity were used for water heating and space heating. These three applications accounted for over a third of residential electricity consumption in 1983. These appliances are particularly important in load management efforts because they typically are major contributors to fluctuations in overall demand for electric power (see figure 5-9).

In the commercial sector, lighting and air-conditioning are the most important applications for electric power, each accounting for roughly 40 percent of electricity use. Much of the rest is used in used in water and space heating. The use of electric power for air-conditioning and space heating in the commercial sector is especially important. They accounted for 12 percent of national electricity use (1984) and contribute significantly to daily fluctuations in demand.

In industry, the largest fraction of electric power—over 50 percent in 1984—is used in machine drives. Electrolysis accounted for about 13 percent industrial electricity use; slightly less was used in generating process heat. Most of the balance went for for space heating and lighting. While industry uses a large amount of the electrical energy, its cyclical variations tend to be less extreme than those in the commercial and residential sectors.

As table 5-7 suggests, the individual applications which account for the largest portion of electricity use is found in the industrial sector, followed by the commercial sector and then the

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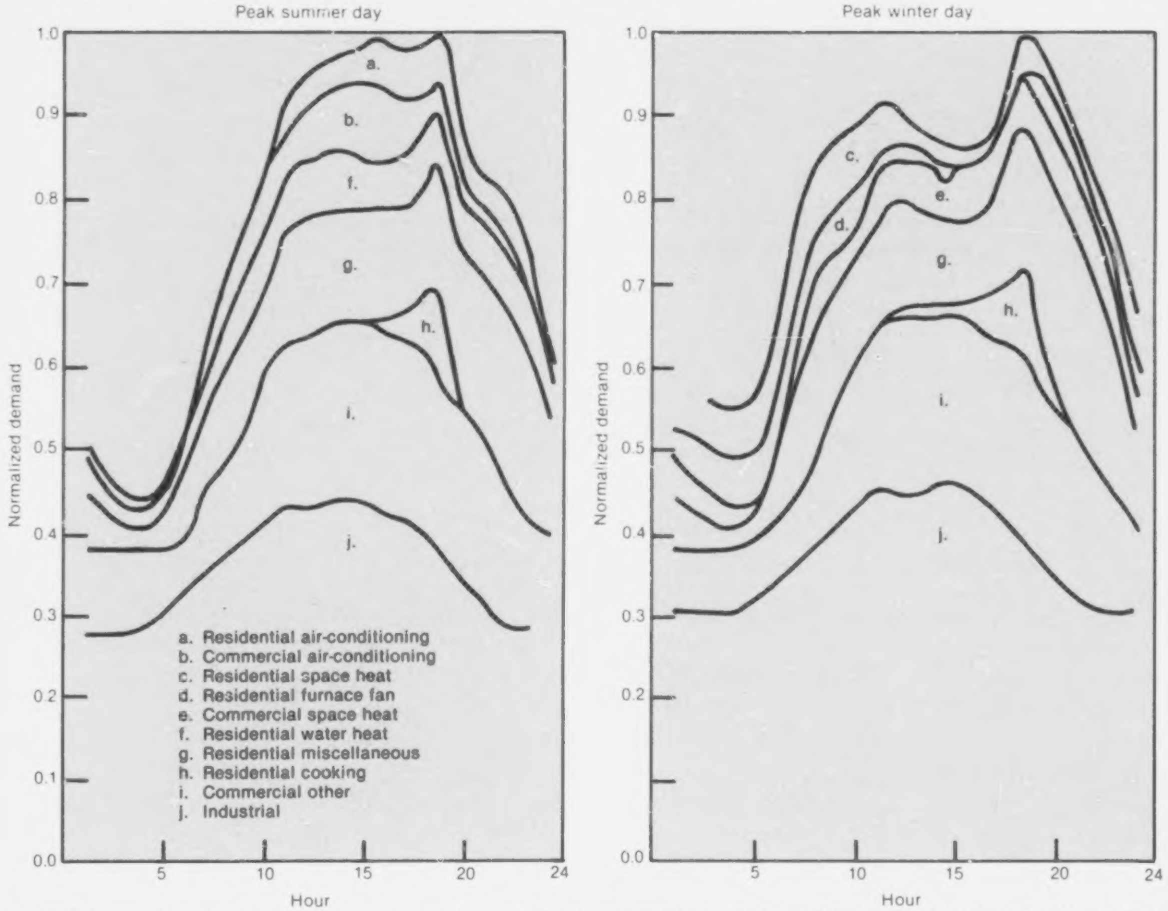
[20] For example, see: Rene H. Males, "Load Management—The Strategic Opportunity," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 3-1 through 3-8.

[21] End-use energy consumption excludes the energy used to generate and transmit electricity to the end-use sectors, and accounts for only the energy used by the consumer.

Figure 5-9.—Illustration of Customer Class Load Profiles—North Central Census Region in the 1970s



SOURCES: Decision Focus, Inc., *Integrated Analysis of Load Shapes and Energy Storage*, March 1979; and Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597

residential sector. The importance of individual sectors varies widely from region to region and from utility to utility, as does the importance of specific applications within those sectors.

While there will be some changes in the relative importance of some electricity end uses over the coming years, the 1983 patterns (table 5-7) provide a general indication of which loads will be most important in shaping the demand for utility power—and in load management efforts—in the 1990s. The success of load management will depend on the ability of the utilities to influence customer demand in those applications.

Other Variables

In addition to the characteristics of a utility's customers, other variables are important indicators of the potential for load management. Generally speaking, load management tends to be favored where load factors[22] are low and where peaking capacity is expensive and base load capacity is cheap. Also, load management is favored where utilities purchase a large portion of their

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[22] Load factor is the ratio of the average load supplied during a designated period (e.g., hourly, daily, monthly, or annual) to the peak or maximum load occurring during the same period.

Table 5-7.—Major Uses of Purchased Electricity in the United States, 1983

Sector	Application	Billions of kWh (estimated)	Percent of total U.S. purchased electricity
Industrial	Machine drive . .	539	25
Commercial	Air-conditioning	231	11
Commercial	Light	220	10
Residential	Air-conditioning	111	5
Industrial	Electrolysis	103	5
Residential	Water heating . .	97	4
Industrial	Process heat . . .	97	4
Residential	Space heat	70	3
Commercial	Water heating . .	59	3
Industrial	Light	47	2
Commercial	Space heat	29	1
Total		1,603	74

SOURCES: **Industrial:** The breakdown for industrial electricity use was obtained from table 1-10 in Pradeep C. Gupta and Ahmad Faruqui, "EPRI Perspective on Industrial Electricity Use," *Proceedings: Forecasting the Impact of Industrial Structural Change on U.S. Electricity Demand*, Battelle Memorial Institute, Columbus Laboratories (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3816, pp. 1-1 through 1-17. The percentage breakdown provided in the article was for 1980. It was assumed in the above calculations that the breakdown in 1980 was the same as that in1983. These percentages were applied to the Department of Energy estimates of industrial purchases of electrical power, see U.S. Department of Energy, Energy Information Administration, *Energy Conservation Indicators 1983 Annual Report* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0441, table 33.

Commercial: The breakdown for commercial energy consumption was obtained from Oak Ridge National Laboratory's *A User's Guide to the ORNL Commercial End Use Model* (Oak Ridge, TN: ORNL 1980). It was assumed in the above calculations that the breakdown provided by ORNL was the same as that which characterized the commercial sector in 1983. These percentages were applied to the DOE estimates of industrial purchases of electrical power, as provided in table 24 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.

Residential: The breakdown for residential energy consumption was obtained from an estimate provided from U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1984* (Washington, DC: U.S. Government Printing Office, 1984), DOE/EIA-0383 (84), table A6. The breakdown was applied to the 1983 estimate of residential electricity purchases, as provided in table 11 of the *Energy Conservation Indicators 1983 Annual Report*, op. cit., 1984.

electric power rather than generating it themselves. These characteristics, alone or in combination, may encourage load management. Though these features vary from one utility to the next, some regional generalizations can be made. (See the section on load management in chapter 7.)

Current Status of Load Management Efforts

Because of the large variety of forms which load management may take, it is very difficult to accurately determine the extent to which it is being exercised by utilities. There are, however, two key indicators of load management activity which have been examined in detail in surveys by the Electric Power Research Institute (EPRI). First is the implementation by utilities of innovative rates designed to modify customer electricity demand patterns. Second are activities by the electric utilities relating to direct load control.

Innovative Rates

The Electric Power Research Institute in 1983 sponsored a survey of electric utilities to gather information on innovative rates in the utility industry. EPRI found that at least half of the investor-owned utilities in the United States had implemented or proposed innovative rates; and about 6 percent of publicly owned utilities had done so.[23] The most commonly applied rates were time-of-use rates, rates which are linked to the specific time at which the power is needed. Figures 5-10 and 5-11 illustrate how a time-of-use rate can affect electricity demand.

About 20 million electricity customers served by utilities which responded to the EPRI survey are affected by innovative rates. That is about 21 percent of all the utility customers in the United States.[24] Most of the customers under the innovative rates were in the residential sector, though

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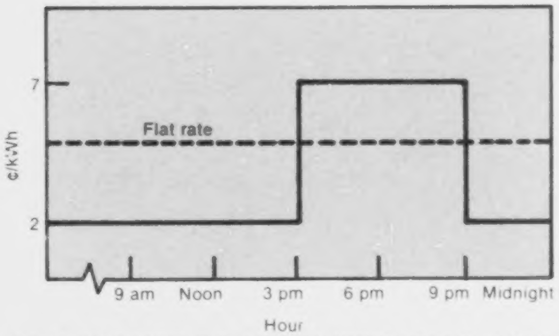
[23] The estimates are based on information provided by the Electric Power Research Institute (Ebasco Business Consulting Co., *Innovative Rate Design Survey* (Palo Alto, CA: Electric Power Research Institute, 1985), EPRI EA-3830).

In the responses to a checklist sent to the members of the American Public Power Association and the National Rural Electric Cooperative Association, approximately 175 members reported innovative-rate design activity. Since there is a total of about 3,069 publicly owned utilities in the United States, this amounts to about 6 percent of all publicly owned utilities. This 175-member estimate should be treated as a low figure, as it does not include utilities which were not members of the two associations; nor does it include utilities who did not respond to the checklist.

In the case of the investor-owned utilities, EPRI found that 106 utilities have either proposed and/or implemented innovative rates. Since there are about 204 investor-owned utilities in the United States, this amounts to about 52 percent of those utilities. As with the publicly owned utilities, this should be treated as a low figure. The number is based on only 123 survey responses—about 60 percent of investor-owned utilities.

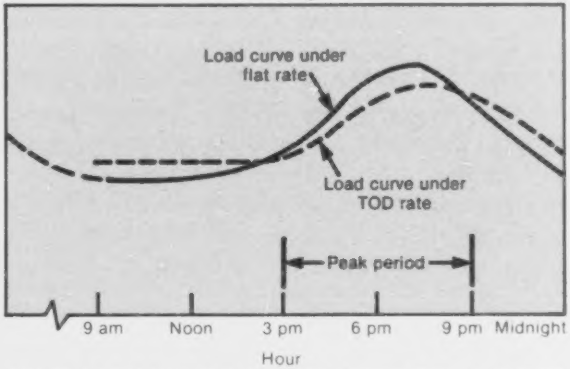
[24] This is based on an estimate made by the Edison Electric Institute that there was a total of 97 million ultimate customers of the entire electric utility industry as of Dec. 31, 1983 (Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* (Washington, DC: EEI, 1984), p. 58).

Figure 5-10.—An Example of Time-of-Day Rate



SOURCE: Jan Paul Acton, et al., *Time-of-Day Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., 1983), R-3086-HF.

Figure 5-11.—Time-of-Day Rates Shift Patterns of Electricity Use



SOURCE: Jan Paul Acton, et al., *Time-of-Day Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., 1983), R-3086-HF.

there were a substantial number of industrial and commercial customers as well.[25]

Unfortunately, very little is known about the precise impact of these rates on electricity supply and demand nationwide. To the extent that assessments have been made, they typically have been utility-specific and limited in scope. The available evidence indicates that utilities have, in many instances, effectively and economically managed loads by implementing carefully structured rate programs.[26] But this has not always been the case. Rates in some cases have been developed and implemented which have had little or no impact on demand patterns. This is an indication of the difficulty in understanding customer demand patterns and in designing and implementing rates for load management.

Load Control

Utilities have controlled loads in the United States for about half a century. The earliest efforts in the United States, in the 1930s, involved the installation by utilities of timers on appliances[27] to inhibit appliance operation during preselected periods. But only within the last decade have utilities seriously considered load control as a potentially attractive investment.

The 1983 EPRI survey also sought to assess utility activities in load control.[28] While, as mentioned earlier, numerous objectives could be served by load control, the survey found that it has been viewed primarily as a means of reducing wholesale power costs and has been most vigorously pursued by utilities which purchase much of their power from other utilities. By far the most active in load control are rural distribution cooperatives and municipal utilities. Together they accounted for one-third of the loads controlled in 1983.

As is the case with innovative rates, the largest number of customers subject to load control falls within the residential sector (see table 5-8). Table 5-6 summarizes the load management activity which was underway among U.S. residences,[29] and provides a rough idea of the number of points which are available for control. The table suggests that only a very small portion—perhaps only a few percent—of the residential appliances are subject to load control.

Given the large potential in the South (see table 5-6), it is not surprising that in 1983, roughly

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[25] According to a study by the Rand Corp. (Jan Paul Acton, et al., *Time-of-Day Electricity Rates for the United States* (Santa Monica, CA: The Rand Corp., November 1983), more than 12,000 commercial and industrial enterprises fell under time-of-day rates (the major form of time-of-use rates) by the early 1980s.

[26] Ibid.

[27] Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

[28] Ibid.

[29] The table includes only space heating, water heating, and air-conditioning. It does not include pool pumps and other controlled points.

Table 5-8.—Load Control: Appliances and Sectors Controlled in 1983 Under Utility-Sponsored Load Control Programs

Appliance/sector	Number of points controlled
Electric water heaters:	
All sectors	648,437
Residential	643,910
Commercial	4,527
Air-conditioners:	
All sectors	515,252
Residential	491,675
Commercial	23,577
Irrigation pumps:	
All sectors	14,261
Space heating systems:	
All sectors	50,238
Residential	48,546
Commercial	1,692
Swimming pool pumps:	
Residential	258,993
Miscellaneous:	
All sectors	13,710
Residential	13,088
Commercial	34
Industrial	588
All appliances:	
All sectors	1,500,891 (100%)
Residential	1,456,212 (97%)
Commercial	29,830 (2%)
Industrial	588 (negligible)
Agricultural	14,260 (1%)

SOURCE: Synergic Resources Corp., *1983 Survey of Utility End-Use Projects* (Palo Alto, CA: Electric Power Research Institute, May 1984), EPRI EM-3529.

58 percent of the load control points[30] nationwide were located there; 37 percent were in the North Central region, followed by the West, with 11 percent. The Northeast, though it appears to have somewhat more controllable points than the West, accounts for less than 2 percent of the points currently controlled.

The nationwide impact of the load control measures in place in 1983 has not been precisely determined. It can be very roughly estimated, however. The average peak load reduction[31] reported in the 1983 EPRI survey of 298 utilities was 1 kW for each controlled residential air-conditioner and 0.6 (summer) to 0.9 (winter) kW for each controlled residential water heater. These averages should be interpreted with caution; the results vary widely from one utility to the next. Since there were 643,910 residential water heaters and 491,695 residential air-conditioners controlled in 1983, the peak load reduction might have been roughly 880 MWe in the summer (if all the water heaters were controlled during the summer) and 580 MWe (if all the water heaters were controlled during the winter).

While positive results were observed for many load control projects, utilities often were not wholly satisfied with the performance of the load management technologies they used. In particular, equipment has been relatively unreliable. The problems resulted from a combination of factors. To some extent these resulted from inferior products, or other supplier problems; but many also resulted from the manner in which the technology was used. Most of these problems have been alleviated over time and appear to be the kind of passing difficulties which are to be expected with the application of new configurations of technologies to relatively complex circumstances.[32]

Potential Peak Load Reductions From Load Management

The potential peak load reduction from load management in the 1990s depends on many factors. At the most basic level, the peak load reduction from any load management program depends on: 1) the total numbers of customers and electricity using appliances, 2) the nature of the appliances and the manner in which they are used, 3) the extent to which customers participate in the load management effort, and 4) the peak load reduction achieved for each appliance. These variables in turn depend on many other conditions, some of which vary greatly from utility to utility, and even within the territory of a utility. Only now are methods being developed and refined for predicting the results of load management programs.[33]

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[30] A "point" in this discussion refers to the point at which the specific load is controlled. For example, if a home has a single air-conditioner with a load control device, that air-conditioner constitutes a point. If the home had several such air-conditioners, each with its own load control device, each would be considered a point. Consequently, any one customer may account for several points, depending on the number of independently controlled appliances on the premises.

[31] The peak load reduction is the magnitude of the additional power which would have been required to meet demand had the appliance not been controlled.

[32] Analysis and Control of Energy Systems, Inc., *Residential Load Management Technology Review* (Palo Alto, CA: Electric Power Research Institute, 1985), EPRI EM-3861.

An accurate, reliable, and detailed estimate of the nationwide potential of load management requires an effort beyond the scope of this report. However, strong evidence suggests that there are many opportunities for increasing the number of customers and points under load management programs. It is apparent that though innovative electricity rates are becoming more common in the United States, most utility customers do not yet fall under such rates. Likewise, as table 5-6 suggests, only a tiny fraction of customer loads are controlled through load control programs.

Evidence suggests that customers in many—*though not all*—instances would be favorably disposed towards both special rates and load control.[34] The precise customer response depends not only on the character of the customers but also the nature of the load management effort.[35] Where rates and load control are implemented, significant peak load reductions may occur. Considerable variation in customer attitudes toward load management and in the impacts of load management likely will characterize different utilities across the country.

The management of a relatively small number of large individual loads, such as those commonly found in the industrial and commercial sector, typically will present fewer problems and impose lower costs than management of a large number of small loads. A rate structure which encourages load management may be applied readily and effectively to large users. The deployment by utilities of the technologies required to implement some of these rates among such users is generally inexpensive relative to the potential gains for the utility. Moreover, once the economic incentive is offered, the users themselves (industrial and commercial) frequently are capable of deploying technologies which are effective in changing their demand in accordance with the utility's incentives and their own economic interests.[36]

Where a large number of small users are involved such as in the residential sector, the difficulties are more limiting. In 1983, there were over eight times as many residential customers in the United States than commercial and industrial customers. And the average residential customer used less than 9 MWh/year, compared with 1,560 MWh/year by the average industrial customer and 53 MWh/year by the average commercial customer.

Consequently, special rates tend to be less readily and profitably applied to the residential sector, and the cost-benefit ratio for the utility for each load managed is likely to be larger. In addition, the cost and difficulty of installing, maintaining and operating the equipment, required as an adjunct to such rates may be considered excessive by utilities. Compounding the problems is the utilities' uncertainty about future residential electricity use, and the manner in which it would change under alternative load management programs.

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[33] See the following: 1) Robert T. Howard, "Estimating Customer Response to Time-of-Use Rates," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 16-3 through 16-4. 2) T.D. Boyce, "Estimating Customer Response to Direct Load Management and Thermal Energy Storage Programs," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 16-7 through 16-10.

[34] See: 1) Thomas A. Heberlein & Associates, *Customer Acceptance of Direct Load Controls: Residential Water Heating and Air Conditioning* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EA-2151; 2) Thomas A. Heberlein, "Customer Attitudes and Acceptance of Load Management," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 4-1 through 4-21; and 3) Ebasco Business Consulting Co., *Innovative Rate Design Survey*, op. cit., 1985.

[35] See Tom D. Stickels, San Diego Gas & Electric, "Analyzing Customer Acceptance of Load Management Programs," *Workshop Proceedings: Planning and Assessment of Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-3464, pp. 16-1 through 16-3.

[36] For an assessment of the possible costs and benefits of load management using incentive rates for seven major industries, see: Chem Systems, Inc., *The Potential for Load Management in Selected Industries* (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EA-1821-SY.

At present about 1.5 million points are controlled,[37] which is only a small fraction of the number of residential loads that could be controlled (probably less than 1 percent). A much larger potential exists in every region of the country, particularly in the South where residential electricity demand is high and there are a large number of all-electric homes. A recent survey of the stated intentions of utilities indicates that if currently planned load control programs are implemented, at least 5 million new points may be controlled by 1990.[38] Another report suggests that 8 million points will be controlled by 1990 and 20 million points by 1995.[39] [40]

The potential magnitude of the impact of load control is difficult to gauge. Evidence from current load management efforts indicates that the impact could be quite sizable. If, for example, one air-conditioner in each of 5 million homes were controlled, and if an average peak load reduction of 1 kWe were obtained, a peak load reduction of about 5,000 MWe would result. Note that nearly 50 million homes have air-conditioning and that many of these have more than one air-conditioner. Also residential air-conditioning represents only one of many loads which could be controlled.

Overall, the potential for load management is such that it is an important strategic option in the U.S. electricity supply outlook in the 1990s. Whether utilities fulfill this potential will depend on the cost, performance, and risk of load management technologies and on the ability of the utilities to manage those technologies and develop innovative rates.

Technologies for Load Management

Given the magnitude of demand in the residential sector, its importance in contributing to the fluctuations in demand for electric power, and the characteristics of individual residential customers, it is not surprising that the technology-related problems of current utility efforts to manage loads center on small users. This will also be the emphasis here. Many of the technologies, issues, and problems in the residential sector, however, also are applicable to the other sectors.

Two principal groups of technologies are required in load management:

1. **Advanced meters:** Meters measure electricity use; recorders, often integrated into a single device with the meter, record this information for later use. The data help in developing load management strategies, in implementing them, and in assessing their results. They also facilitate the application of rates which encourage the deployment of customer-owned and operated load management technologies.
2. **Load control systems:** In order to control loads, utilities may need to be capable of communicating with the customer. *Communications systems* provide this link, allowing the transmission from the utility to the customer, and perhaps vice versa. Required for successful load control systems are *decision-logic technologies* which interpret information and automatically generate decisions necessary for effective load management.

Advanced Meters[41]

The predominant residential electric meter and recorder used in the United States is the single-phase (see chapter 6 for definition of single phase and other relevant terms) electromechanical watt-hour meter which requires periodic reading by an individual on location. A variety of solid-state meters, "hybrid meters"[42] and other ancillary equipment (including communications technologies) are available and being developed to assist in meeting the rising information needs of load management. Among the equipment being developed is hardware which can be retrofitted to existing equipment to enhance the capabilities of common meters.

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[37] Synergic Resources Corp., *1983 Survey of Utility End-Use Projects*, op. cit., 1984.

[38] Ibid.

[39] The Laird Durham Co., *The United States Market for Residential Load Control Equipment, 1983-1995* (San Francisco, CA: Laird Durham Co., 1984).

[40] A recent Frost & Sullivan report suggests that 7 million points will be controlled by 1992 (Frost & Sullivan, *Electric Utility Customer Side Load Management Market* (New York: Frost & Sullivan, 1984), as reported in "Load Management Systems Will Control Seven Million by 1992," *Electric Light & Power*, vol. 62, No. 8, August 1984, p. 47).

[41] Strictly speaking, a meter only measures electrical power or energy. Here however, the term is used loosely to include devices which not only perform the measuring function, but also record and perhaps even manipulate the data.

[42] A hybrid meter is one which couples the common meter's rotating sensing-element to a solid-state microprocessor.

Advanced meters can perform many more tasks. For example, they may provide the customer not only with data on current and past use, but also information on present costs and other matters; that additional information could be wholly or partly generated by pre-programmed equipment on site or transmitted from a remote location. Where time-of-use rates were being applied as part of a load management program, the information is essential for the consumer. Alternatively, the meter could provide direct and automatic input to the load control system. For example, a "demand-subscription service" meter will automatically trigger a sequence of events designed to curtail load when the meter indicates that demand has exceeded a specified level.

Currently available advanced meters, however, often are expensive, unreliable, and short-lived, relative to conventional meters. Considerable evidence indicates that the technical problems could be resolved relatively easily, but developers appear reluctant to do so without assurances that a major market exists. Similarly, costs can only be reduced sufficiently through mass production and deployment.

Another consideration is that the conventional meter is a long-established fixture in U.S. utility operations. It performs the task expected of it without imposing inordinately large operating and maintenance costs. While new meter designs could in the long run be superior, they would require changes. People would have to be trained. Some workers might no longer be needed; others, with different skills, would be required. New maintenance facilities likely would be needed, and operating procedures would have to be modified to accommodate the new technology.[43]

While problems remain, no major unresolvable technological barriers impede the deployment of advanced meters. Rather, the problems appear to be related to the development of an early market among utilities and to the need for changes in utility practices. The evidence indicates that unless concerted efforts are made to eliminate these impediments by stimulating demand, the deployment of advanced meters will be a slow process. Their conventional competitors likely will predominate well past the close of this century, though their position will be eroded slowly by the newer technologies.

Load Control Systems

Load control systems vary in the extent to which control is concentrated on either side of the meter (customer or utility); in the extent to which information from the customer side-of-the-meter is used and in the nature of that information; and in the degree of automation on the customer side-of-the-meter. Some require relatively active customer participation and a low level of automation. For example, the utility may simply call up the customer and ask that his load be reduced as much as possible; the customer could respond by turning various appliances off, basing his actions on a multitude of considerations. Other systems, however, may be more automated and are capable of operating with little or no customer intervention.

Load control systems are classified into three categories—local, distributed, and direct control—according to the degree to which decisions are centralized and the extent to which the utility and customer interact before the load is manipulated. In a *direct control* system, the load is controlled by the utility without any immediate input in any form from the customer's side of the meter (see figure 5-12). This in the past has been the dominant form of load control.

In a *local control* system, the load is controlled from the customer's side of the meter, without immediate input from the utility (see for example figure 5-13). With local control systems, manipulation of the customer's load is based solely on immediate input from only the customer's side of the meter. Utility involvement is re-

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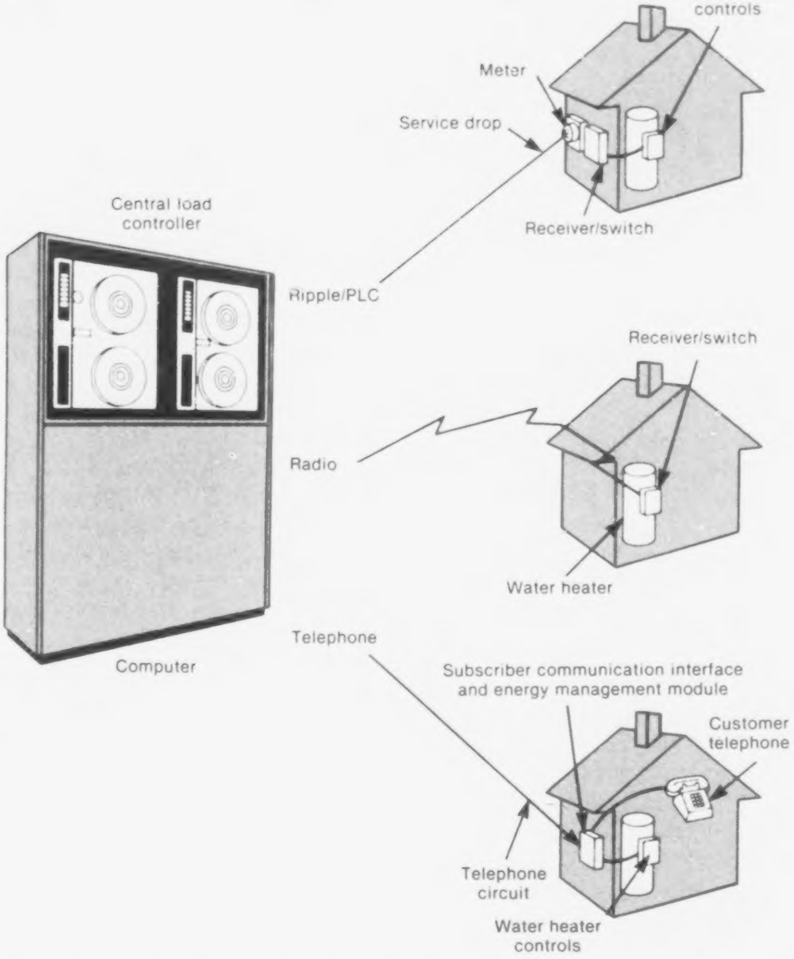
[43] "How to Get Meter Readers to Use Computers," *Electrical World*, vol. 198, No. 10, October 1984, pp. 26-28.

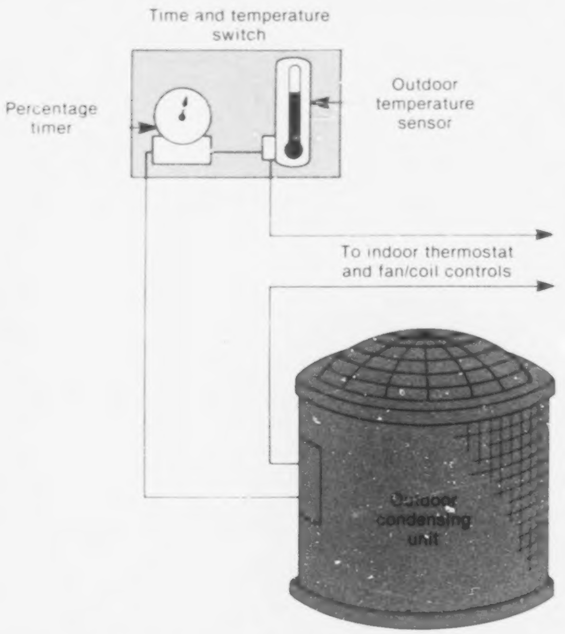
Figure 5-12.—A Direct-Control Load Management Technology: Domestic Water Heater Cycling Control


Water heater controls
Meter
Service drop
Central load controller
Receiver/switch
Ripple/PLC
Receiver/switch
Radio
Water heater
Telephone
Computer
Subscriber communication interface and energy management module
Customer telephone
Telephone circuit
Water heater controls

Domestic water heater cycling involves direct, real-time utility control over the operation of residential water heaters. Water heating is one of the few residential loads that is truly deferrable in that a water heater can be turned off for extended periods of time (up to 6 hours in some cases) without affecting the customer's lifestyle. By directly cycling water heaters (through a communication system, as opposed to using timers or other local controllers), the utility can vary when and how much control is exercised. Water heater cycling is generally exercised only during periods of peak demand or high marginal supply costs.

SOURCE: Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

Figure 5-13.—A Local-Control Load Management Technology: Temperature-Activated Switches


Time and temperature switch
Percentage timer
Outdoor temperature sensor
To indoor thermostat and fan/coil controls
Outdoor condensing unit

A temperature-activated time switch (T&T) is used to reduce air-conditioner operation time during utility peak periods. The two main components are an outdoor thermostat and an adjustable percentage timer. When outdoor temperatures reach a preset limit, the timer regulates air-conditioner run times by a preset percentage, generally 75 or 50 percent (22.5 minutes on and 7.5 minutes off or 15 minutes on and 15 minutes off in every 30-minute period, respectively). Control is terminated when the outdoor temperature drops to the preset deactivation temperature.

SOURCE: Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

stricted to indirect inputs such as incentive rates. Local control devices have been encouraged where appropriate rates have been instituted. But their application has been limited in the residential sector, in part because such rates may require replacement of conventional meters with more advanced meters.

Between the direct and local control systems are variations collectively termed *distributed control* systems, where key decisions are made on both the utility and the customer side-of-the-meter, and where immediate inputs from both are possible. A distibuted-control system is pictured in figure 5-14. In EPRI's 1983 survey of utilities, it was found that, 86 percent of utility-sponsored load control projects—1.2 million points—utilized direct control systems, while 278,000 points were controlled by distributed control systems, and 10,000 points fell under utility-sponsored local control programs. Many more points are locally controlled without the utilities' direct sponsorship, but with indirect utility support, usually through direct incentives and rate structures.[44]

The key problem encountered in all control systems is the management of loads in a manner which is satisfactory to the customer yet which provides an acceptable degree of control and predictability to the utility. The greater the utilities' direct control, the greater the risk of customer dissatisfaction. Conversely, systems which give the utility less direct control over the load—while perhaps alleviating communications and customer problems—risk reducing the utility's capacity to effectively manage the load. While direct control has dominated in the past, utilities are increasingly moving towards distributed and local control.

Discussed below are the two key technological components of load control: "decision-logic" technologies and central controllers and communications technologies.

Central Controllers and Communications Technologies.—Direct and distributed control systems use technologies which fall into three categories: central controllers, transmission systems, and a receiver/switch at the customer's end of the system.[45] If the system communicates in two directions, a "transponder," which both receives and transmits, is required on the customer side of the meter; and a receiver must be in place on the utility's side of the meter to receive the information sent from the customer's transponder.

The controller generates commands which are encoded and dispatched through some transmission system, and received by the receiver which translates the encoded message and accordingly manipulates the load. While the hardware component of modern computerized controllers is

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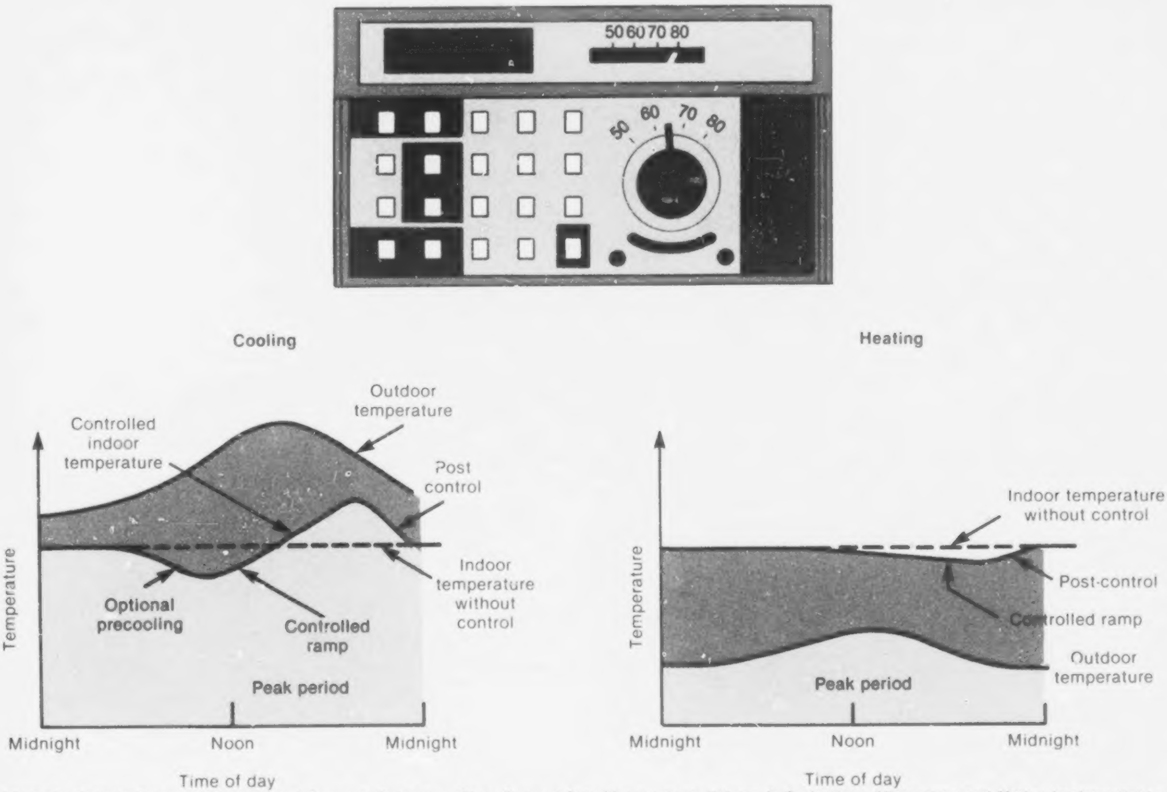
[44] Synergic Resources Corp., *1983 Survey of Utility End-Use Projects*, op. cit., 1984.

[45] Ibid.

Figure 5-14.—A Distributed Control Load Management Technology: Load Management Thermostats

A load management thermostat is a microprocessor-based device that allows gradual indoor temperature increases or decreases in response to electric utility needs, thereby maintaining the natural diversity of loads while reducing the duty cycles of heating or cooling equipment. The result is a reduction in customer demand. The preset rate and length of temperature ramping can vary; fixed maximum and minimum temperature limits are also programmed into the device to prevent extremely uncomfortable conditions. Customers' thermostat setpoint adjustments are overridden during utility control periods. Emergency load shedding can also be accomplished using this device.



SOURCE: Battelle-Columbus Division and Synergic Resources Corp., *Demand-Side Management, Volume 3: Technology Alternatives and Market Implementation Methods* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA/EM-3597.

well developed and readily available commercially, the software is not. Recent utility experiences indicate that software deficiencies are the primary cause of difficulties in the implementation of load management programs. Current evidence suggests that software problems are surmountable, but that effective software is likely to require considerable time to develop and refine, and to some extent must be customized for each utility.[46]

The communications system—which includes the transmission system and the receivers—has been subject of greatest discussion among utility operators. A variety of systems are available to choose from:

- **Radio**: This is currently the predominant communication system used for load management.
- **Power-line carrier (PLC) systems**: These systems use the utility's already installed transmission or distribution networks (or both) to carry the signal.

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[46] Ibid.

- **Telephone**: Telephone lines can be used in several different ways in communicating information to and from the utility.
- **Cable TV**: Using a cable modulator, the utility injects its signals into the cable network. Receivers are "hard-wired" to the cable at the customer's end.
- **Hybrid communications systems**: These systems incorporate two or more of the above systems in one load control system. This allows incorporation of the best features of both systems while avoiding some of their pitfalls.

Each of these communications systems has its advantages and disadvantages. They differ in the amount of information which can be communicated over any period of time; the reliability with which the communication takes place; the extent to which the communication system already exists; the cost and technical risk associated with the system; and the ease with which the utility can deploy and utilize the system in conjunction with a load management program. It is important to note that the hardware itself is in many instances fully mature, and involves little technical risk. In some cases, however, technical improvements remain to be made and costs may still be reduced.

The current debate over communications systems centers around which best serves the needs of the utility. These needs extend beyond the use of the communications network for load control, and touch on their application to remote meter-reading, distribution system automation,[47] and other uses. The needs also extend beyond the near term in that the utilities seek systems which are flexible enough to perform a variety of future tasks.

For example, one choice the utilities have is between one- and two-way communications systems. One-way systems are *sufficient* for load control, but two-way systems allow utilities to monitor more closely the results of load control by transmitting information from the customer to the utility. Furthermore, the two-way system may be exploited to obtain billing information which now requires a visit by the meter reader. And a two-way system may be used in automating the distribution system.

Complicating the utilities' evaluation of communications options is the fact that two basic options are available with respect to control and use. The utility may invest in a system which it alone controls and uses. Or the utility may invest in an information transmission system the control and use of which it *shares* with other users. Where others are involved, the costs of the system can be shared, but this arrangement also carries with it the possibility of technical problems in coordination as well as opportunities for conflict between the parties.

Hence, where shared communications systems are considered by utility investors, the cost advantages of such systems are weighed against the practical difficulties of cooperating with other people and organizations. The ultimate choice of the technology in such cases may depend as much on the ability of the utility to successfully overcome these difficulties as it does on the cost of the investment to the utility.[48] [49] [50]

Decision-Logic Technologies.—Distributed and local load control systems are distinguished from the direct control strategies in that information generated on the customer side of the meter promptly influences the manner in which the customer's load is managed. The locally provided information can be complemented by instructions transmitted either from the utility side of the meter through a rapid "real-time" communication system or from a pre-programmed utility-controlled device on the customer's premises.

The interpretation of locally derived information, the generation of the appropriate decisions, and the manipulation of the load can all be automated in order to minimize or eliminate the need for active and routine human involvement on the customer's premises. This is done with "local decision-logic" devices which provide a degree of "local intelligence." A variety of devices may serve this purpose. These vary in their cost, performance, and uncertainty. Some presently are available commercially at acceptable levels of cost and performance. Others must be technically improved, or their costs must be brought down before they will be deployed at significant levels. Generally, the major technical problem is in programming the devices so that they manage loads in ways that are acceptable to the customer while serving the utility's load management needs.

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[47] Distribution automation is the remote control of the distribution system which transmits electricity to customers from local substations; such control could offer significant improvements in overall power system operation.

[48] Synergic Resources Corp., *1983 Survey of Utility End-Use Projects*, op. cit., 1984.

[49] David P. Towey and Norman M. Sinel, "An Electric Utility Explores the Use of Modern Communications Technologies," *Public Utilities Fortnightly*, vol. 113, No. 9, April 1984, pp. 23-33.

[50] Alan S. Miller and Irving Mintzer, *Draft Report: Evolving Load Management Technologies: Some Implications for Utility Planning and Operations* (Washington, DC: World Resources Institute. 1984).

Ancillary Technologies Owned or Controlled by the Customer

In addition to the load management technologies discussed above, there are technologies which can be installed and operated by the customer to mitigate the potentially adverse effects of load control (direct, distributed, or local) on the customer. Among the technologies are two major possibilities:

1. **Electric and thermal energy storage:** A wide range of electric as well as thermal energy storage schemes exist for mitigating the effects of periodic curtailments in electricity supply. For example, a battery could be installed on the customer's side of the meter; the battery would be charged when power is more readily available and the customer could draw on it instead of from the grid during peak periods. If a load management program applied to an electric water heater threatens to leave the customer without sufficient hot water, a larger thermal storage device could be used. This device would be heated with electricity during off-peak periods. Of particular importance is "cool storage" for commercial establishments which uses electricity during off-peak periods to cool a medium such as water which then cools the building during peak periods.[51]
2. **Energy conservation:** Of course, energy conservation can also be employed as part of a mitigation program. For example, if curtailing the operation of an electric heater might result in lower house temperatures, insulation could be used to lower heat losses and keep household temperatures at a comfortable level.[52]

Some of these technologies are inexpensive, reliable, and present little risk. Others, such as large batteries systems, are less mature commercially and must overcome a variety of impediments before they could be deployed extensively (see chapters 4 and 9). Note, too, that the deployment of these technologies in many cases depends heavily on the rate structure or other incentives provided by the utilities.

Major Impediments to Load Management

Several difficulties must be overcome if load management is to be extensively implemented in the 1990s. It is necessary for utilities to develop a detailed understanding of the manner in which their customers now use electricity and are likely to use electricity in the future. To this must be coupled information regarding the utility's future supply of electric power. It also is important for utilities to identify and understand the many combinations of load management strategies which can be pursued. Each option must be weighed and compared not only to other load management options but also to other alternatives such as conventional generating technologies.

These difficulties are aggravated by the frequent lack of adequate analytical tools with which to evaluate load management. The planning and implementation of a load management program requires information and skills that differ from those needed for building powerplants and other more traditional utility planning activities.[53] Moreover, as will be discussed in chapter 8, systematic analytical tools for comparing load management strategies with other strategic options are not widespread.

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[51] See: 1) RCF, Inc., *Commercial Cool Storage Primer* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EM-3371. 2) San Diego Gas & Electric, *Thermal Energy Storage: Inducement Program for Commercial Space Cooling* (San Diego, CA: San Diego Gas & Electric, 1983). 3) Electric Power Research Institute, *Opportunities in Thermal Storage R&D* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EM-3159.

[52] Jerome P. Harper and R.E.Sieber (TVA), "Effects of Electric Utility Residential Conservation Programs on Hourly Load Profiles," *Proceedings of the American Power Conference*, vol. 45, 1983, pp. 547-551.

Even if economic benefits of load management are calculated to exceed direct costs, utility operators may prefer not to pursue load management. They may encounter difficulties in reaching agreements to jointly use communications networks with nonutilities. Access may be limited or prohibitively expensive; legal impediments may be encountered.[54] Or customers themselves may be reluctant to allow utilities to control their loads. While this has not been a widespread problem so far—given incentives customers to date have been very receptive[55] [56]—it is a significant unknown that could potentially impede the deployment of direct and distributed load control technologies.[57]

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[53] Energy Management Associates, Inc., *Issues in Implementing a Load Management Program for Direct Load Control* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI EA-2904.

[54] "Justice Department States Cautious on Utility Telecommunications Ventures," *Electric Utility Week*, June 18, 1984, p. 7.

[55] Angel Economic Reports and Heberlein-Baumgartner Research Services, *Customer Attitudes and Response to Load Management* (Palo Alto, CA: Electric Power Research Institute, 1984), RDS 95.

[56] Thomas A. Heberlein & Associates, *Customer Acceptance of Direct Load Controls: Residential Water Heating and Air Conditioning*, op. cit., 1981.

[57] Alan S. Miller and Irving Mintzer, *Draft Report: Evolving Load Management Technologies: Some Implications for Utility Planning and Operations*, op. cit., 1984.

Chapter 6

The Impact of Dispersed Generation Technologies on Utility System Operations and Planning

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Chapter 6

The Impact of Dispersed Generation Technologies on Utility System Operations and Planning

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INTRODUCTION

As the penetration of dispersed generating sources increases in U.S. electric power systems, the implications for system planning, operation, performance, and reliability are receiving increased attention by the industry.[1] The interest in dispersed generating technologies has been stimulated by new Federal laws that have increased the economic attractiveness of such systems. As discussed in chapter 3, the Public Utility Regulatory Policies Act of 1978 (PURPA) opened the way for customer-owned generation mandating interconnection with existing electric systems.

The characteristics of many alternative generating technologies pose both potential benefits and problems for electric system planning and operation. The benefits of dispersed generation generally stem from the potential of substituting plentiful, environmentally acceptable and renewable sources of energy for conventional fuels. Due to the modularity of many of these alternative technologies, deployment on an incremental basis is possible, offering the potential for a more economic expansion of the generation supply. (Other benefits are discussed in chapter 3.)

The nonconventional aspects of dispersed sources of generation concern electric utilities largely because of the industry's lack of knowledge regarding performance of these systems. There is concern, for example, about the lack of utility control over generating resources. In addition, where alternative generation supplies are weather dependent, production is intermittent. Similarly, many cogeneration supplies are highly dependent on the process to which they are linked. Finally, increasing production at the distribution level poses new questions regarding reliability because the delivery system is less reliable at the distribution level than at the transmission or bulk level, i.e. a kilowatt of production at the distribution level is less reliable than one generated at the bulk level.

INTERCONNECTION OF DISPERSED GENERATING SOURCES

Overview

The concept of a dispersed source of generation (DSG) has a variety of meanings, often resulting in some confusion. In this document, a DSG is any generating device (irrespective of size) that introduces power into an electric delivery system, but not at the bulk power level or at the traditional point where a particular utility's conventional generation injects power. By and large, this means electric power production linked to the distribution system of the utility, such as most nonutility power producers that are qualifying facilities (QFs) under PURPA.

While present day electric systems have been structured (in capacity, protection, and configuration) to allow safe and reliable operation without the presence of a DSG device, most researchers agree that with proper modification of the electric network configuration and operation practice, a DSG device can be compatible with the electric system.

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[1] For example, in 1984 the Electric Power Research Institute initiated two major studies entitled, respectively, "Integration of Dispersed Storage and Generation Into Power System Control During Normal System Operations" and "Integration of Load Management Into Power System Control During Normal System Operations."

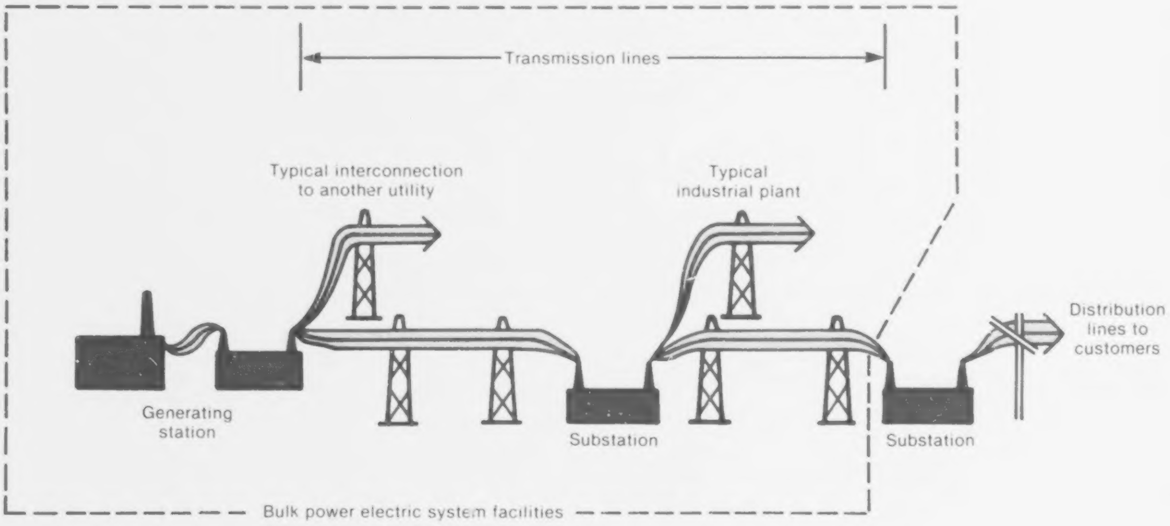
Current Industry Issues

Traditionally, utilities and the agencies that regulate them have primarily been concerned with power flows in electric systems in one direction:[2] either from utility-owned central station powerplants to customers through the transmission and distribution network, or from one utility to another. More recently, however, the incentives offered under PURPA and other Federal and State laws have promoted addition to the electric grid of DSGs which are often nondispatchable and predominantly nonutility-owned. Management of these "two-way" power flows has introduced a new element of complexity into the operation of electric utilities. As a result, utilities and DSG customers have begun to focus some attention on the nature, quality, and cost of the interconnection equipment, and regulators have begun to examine their role in managing the integration of DSGs into the utility grid.

The issues associated with interconnection have their roots in the way power is generated and transmitted through the utility grid. A typical grid (shown in figure 6-1) is composed of several large central generating plants, connected to bulk power transmission lines. These lines typically are maintained at the highest voltages in the grid. Power is then transported through a network of transformers and lower voltage lines until it reaches the customer. Depending on the type of end use, an industrial customer with large process needs may connect directly to primary distribution circuits, while most residential customers connect to secondary distribution circuits at lower voltages.

In addition to power lines and transformers, the grid also includes protection equipment such as circuit breakers, relays, and switches as well as control equipment such as voltage regulators, capacitors, and tap-changing transformers. In powerplants, control of turbine, frequency, and excitation systems is performed. While, a central

Figure 6-1.—Layout of an Electric Power System


Transmission lines
Typical interconnection to another utility
Typical industrial plant
Distribution lines to customers
Generating station
Substation
Substation
Bulk power electric system facilities

SOURCE: North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: NERC, February 1985).

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[2] Utilities have always had some form of dispersed generators on their systems. For example, descending elevators can act as generators and feed power back into the grid (Self Reliance, Inc., *A Guide to Interconnection Requirements in New York State*, prepared for New York State Energy Research and Development Authority (NYSERDA) (Albany, NY: NYSERDA, May 1985), Report No. 85-2. However, the amount of power generated by these dispersed sources has traditionally been a very small proportion of the power generated by the centralized sources.

control center manages, dispatches, and directs the overall operation of the electric grid. Power requirements of the system vary, depending on the time of day and season because the demand for power is changing over time. The protection equipment is used to prevent damage to the grid and its customers from abnormal circumstances or faults and to maintain a highly reliable and dependable supply of electricity. The control equipment provides a high quality of electric power and determines the system's performance standards under normal operation.

Utility customers expect electric power to meet quality and performance standards so that appliances, lights, and motors will operate efficiently and not be damaged under normal conditions. While there is no general agreement among utilities as to the definition of "acceptable" power quality, typically a utility supplies ac power at 120/240 volts (single-phase[3]) for residential and 240/480 volts or higher (three-phase) for industrial customers (with the voltage ranging between 95 to 106 percent). The frequency of the delivered power is 60 Hz (±0.002 Hz).

The types of generating devices used in a DSG can significantly influence its impact on the electric system. The generating equipment can be of many varieties; table 6-1 categorizes different generating types. Rotating machines (most traditional generating equipment) produce ac voltage as either synchronous or induction generators (see box 6A for definitions), while inverters, through the use of power conditioning equipment, change the current from DC sources (such as a photovoltaic array) into AC current. Inverters may be either line-commutated or self-commutated, i.e., either dependent on the utility's voltage and frequency power signal or independent of the utility line.

Table 6-1.—Classification of Dispersed Generating Types

Line independent:
- Synchronous generator
- Forced-commutated converter
- Double output induction with a forced-commutated converter
- DC source with a forced-commutated converter
- Permanent magnet machine
- Field-modulated generators

Line dependent:
- Induction generator
- Line-commutated inverter
- Double output induction with a line-commutated converter
- DC source with a line-commutated converter
- AC commutator generator

SOURCE: Office of Technology Assessment.

Both induction generators and line-commutated inverters consume reactive power (see box 6A for the definition of reactive power) in normal operation and, therefore, one issue for these types of nonutility-owned DSGs is how to compensate for or charge costs of the reactive power consumed. Usually, synchronous generators and self-commutated inverters do not consume any reactive power, i.e., they produce their own, and can operate independently of the utility.

The power conditioning equipment used by inverters produces harmonic frequencies of 60 Hz in the voltage and current signals in the grid. These harmonics, which appear at frequencies that are multiples of 60 Hz, combine to form a complex waveform. The resulting levels of so-called total harmonic distortion (THD) can lead to deterioration in customer appliances and motors. The presence of harmonics can shorten the life of electrical devices by 5 to 32 percent through thermal aging.[4]

Since harmonic voltages affect loads, it is important to understand how they are generated at various parts of the electrical network. Many systems inject current harmonics into the network; these current harmonics are conducted in the various lines and transformers and into the loads, inducing harmonic voltages within the electric system. The location and amplitude of these induced harmonic voltages are largely determined by the electrical parameters of the network. The point of injection and the amplitude of current harmonics, however, are *not* likely to determine the potential impacts; rather problems and their location are determined by network characteristics where harmonic voltages are in-

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[3] See box 6A for definitions of interconnection terms.

[4] E. Fuchs, University of Colorado, *Impact of Harmonics on Home Appliances*, draft contractor report to the U.S. Department of Energy, June 1982, DOE-RA-50150-9.

Box 6A.—Definitions of Interconnection Terms

Single phase: The type of power carried by most secondary distribution lines supplying residential users. Single-phase power consists of one power signal.

Three phase: Consists of three single-phase signals, each one out of phase with the other two by 120°. Three-phase power is used by larger commercial appliances and industrial customers and is usually found in transmission and primary distribution lines.

Power factor: Refers to the difference in phase between the current and voltage signals in a given power line. This difference is measured as the cosine of the fraction (measured in degrees) of the full 360° cycle between the voltage and current maximums. Therefore, a power factor of 1.00 indicates that the two signals are in phase. Power factors less than 1.00 indicate that the voltage and current are out of phase and can either be "leading" if the voltage maximum occurs before the current maximum, or "lagging" if it occurs after. Because power is most efficiently delivered when voltage and current are in phase, it is important that the power factor be as close to 1.00 as possible.

Reactive power: The product of the level of real power and tangent of the phase angle between the voltage and current signals is the value of reactive power, which is measured in volt-amperes-reactive (Var's). Reactive power indicates (along with power factor) the magnitude of the phase difference in the power signal.

Utility-grade relays: Usually refers to relays that have been approved for use in utility power systems and generally have higher quality and cost than standard industrial-grade relays.

Rotating generators: Electric power is produced by the action of a rotating magnetic field that induces a voltage in the windings of the stationary part of the generator. The rotation is caused by mechanical means, such as a steam turbine, and the magnetic field is created by a current flowing in the windings of the rotor. There are two types of rotating generators, based on the way the rotor current is supplied:

- *Synchronous generators:* A rotating machine generator in which the rotor current comes from a separate DC source or the generator itself—thus, the synchronous generator can operate independently from the electric grid.
- *Induction generators:* A rotating machine generator in which the rotor current is supplied by an external AC source, usually the electric grid itself.

Area control error: In an interconnected power system (two or more independent systems—called areas—linked by power interchange tie lines), the change required each area's generation to restore the frequency and net interchange (power flow between the areas) values to their desired levels.

duced. As a consequence, *harmonic voltage problems typically will result in a location remote from the point of injection.*[5]

While there seems to be no general agreement concerning the precise acceptable level of distortion, typically utilities limit THD at the point of injection to less than 5 percent of the current signal with any single harmonic less than 3 percent, and 2 percent of the voltage signal with any single harmonic less than 1 percent. Filtering out this distortion may be expensive for smaller sized DSGs. Therefore, another issue that has surfaced is whether or not all interconnected harmonic sources should be required to meet specified THD standards, or whether these standards should vary according to DSG size and type.

In addition to power quality issues, utilities are concerned with the proper measurement of net power generated by DSG customers. Should all DSG customers be required, and therefore charged, for extra metering equipment? Utilities are also concerned with the liability of DSG customers for utility employee accidents or equipment damage that may result from improper interconnection.

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[5] "Computer Simulation Study," ORNL/SUB/81-95011/1, Oak Ridge National Laboratory, Oak Ridge, TN, August 1983.

As larger proportions of DSGs are installed across the country, another concern is the effect of DSG operation on system dispatching, control, short-term transmission and distribution (T&D) operations, and long-term, central-station capacity planning.[6] As more utilities gain experience with interconnecting customers, guidelines for interconnection are evolving. Efforts are underway to standardize these guidelines (discussed later).

In general, most researchers agree that the technical aspects of interconnection and integration with the grid seem to be relatively well understood; they are discussed in an earlier OTA report.[7] The primary unresolved issue is determining appropriate cost-effective interconnection requirements, i.e., how to balance the utilities' technical risks with interconnection against the nonutility power producers' desire to keep front-end costs of interconnection down. The resolution of this issue will depend on the costs of interconnection equipment, the requirements associated with the utilities' legal obligation to interconnect, and the availability of new hardware and operating practices for DSGs to lower interconnection costs.

INTERCONNECTION PERFORMANCE

Overview

Interconnection equipment generally consists of four major functional subsystems: 1) a *protection and control* subsystem for monitoring DSG power quality and disconnecting the DSG from the grid in case of abnormal conditions on the grid or in the generator itself; 2) a *power conditioning* subsystem PCS) for converting DC to AC if necessary); 3) a *metering* subsystem for measuring: a) power flowing from and to the customer, and b) perhaps time of day; and 4) *other hardware* associated with various types of electrical converters chosen for the DSG. Synchronization equipment is required with many rotary converters; capacitors, power factor correction, transformers, and other equipment can also be required. Each DSG technology may require a somewhat different configuration of subsystems, with the precise configuration depending on current utility guidelines, existing distribution equipment, the type of DSG customer, and other factors.

For example, induction machines and line-commutated inverters may continue to operate after being disconnected from the utility grid, presenting a potential safety problem. Even though these types of equipment require some kind of external power supply to provide reactive current, there may be sufficient reactive power available in that part of the distribution grid near the point of interconnection. This could occur when a utility installs extra capacitors to compensate for the reactive power drain of the DSG. This type of equipment may need extra protective devices to prevent problems associated with unscheduled operation.

Another example is conventional cogeneration equipment. While not requiring extensive investment in power conditioning equipment (these systems typically produce ac power), a conventional cogeneration system requires additional hardware such as: 1) a synchronizer to match its frequency and phase with that of the grid and 2) a transformer for isolation and voltage match. Most inverters have synchronization logic included in the PCS.

Protection and Control Subsystems

Perhaps the most heated debate concerning utility interconnection equipment has centered around the use of protective devices for each DSG configuration. Typically, these devices are: 1) relays designed to detect over- and under-current, over- and under-voltage, and over- and under-frequency of the power produced from the DSG; and 2) filters to eliminate excessive harmonics and electromagnetic interference. A major issue is the setting of these relays to provide an appropriate level of protection, yet avoid "nuisance tripping" of the DSG off-line whenever system power quality conditions vary over the normal course of the day. Of related concern are the cost implications of the tolerance range—the costs for more sensitive protection equipment are higher. These issues are discussed later.

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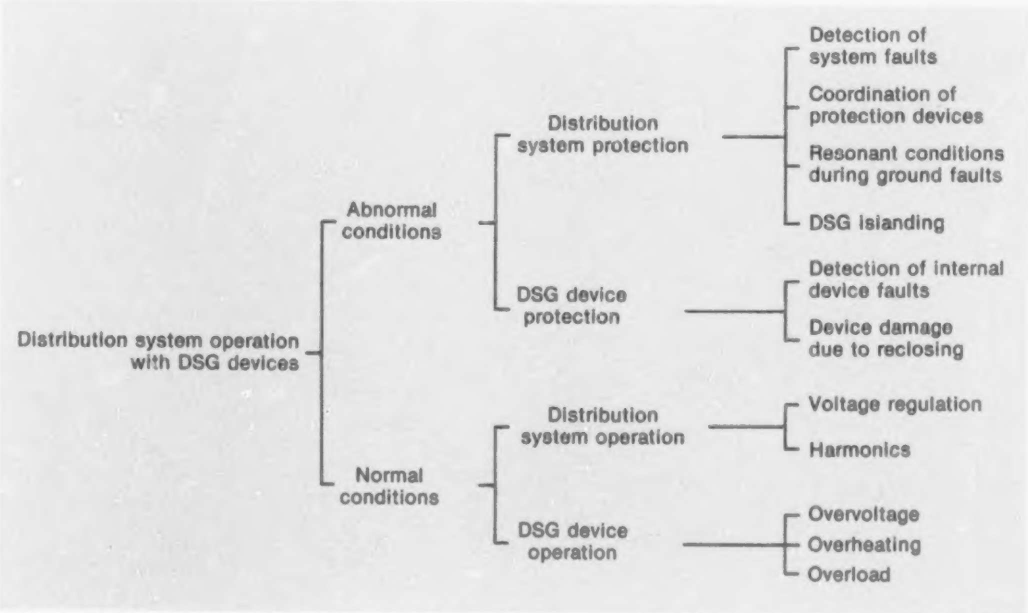
[6] H. Chestnut, et al., "Monitoring and Control Requirements for Dispersed Storage and Generation,"*Institute of Electrical and Electronics Engineers (IEEE) Transactions on Power Apparatus and Systems*, vol. PAS-101, July 1982, pp. 2355-2363; in 1984 the Electric Power Research Institute initiated a major field study on the impact of DSGs on power system operation; see "Integration of Dispersed Storage and Generation Into Power System Control During Normal System Operations," EPRI RFP 2336-1.

[7] U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office February 1983), OTA-E-192.

Protection philosophy covers both the normal and abnormal operating conditions of the electric system. The problem of protecting the electric system involves protection of the distribution system, loads, and other customers as well as protection of the DSG.[8] The most concern arises during abnormal operation when potential damage to the electric system, its customers, and the DSG could occur. The overall protection philosophy and problems are presented in figure 6-2.

Figure 6-2.—Distribution System and DSG Device Protection Problem Areas


Distribution system operation with DSG devices
Abnormal conditions
Normal conditions
Distribution system protection
DSG device protection
Distribution system operation
DSG device operation
Detection of system faults
Coordination of protection devices
Resonant conditions during ground faults
DSG islanding
Detection of internal device faults
Device damage due to reclosing
Voltage regulation
Harmonics
Overvoltage
Overheating
Overload

SOURCE: Electrotek Concepts, Inc., *Impact of Decentralized Generating Sources on Utility System Operations*, contractor report to the Office of Technology Assessment, 1985.

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[8] D.T. Rizy, *Personnel Safety Requirements for Electric Distribution Systems With Dispersed Storage and Generation* (Oak Ridge, TN: Oak Ridge National Laboratory, November 1982), ORNL/TM-8455.

DISTRIBUTION SYSTEM AND DSG DEVICE PROTECTION PROBLEM AREAS

Potential safety problems for electric utility personnel are also of concern to the electric utility industry. Attention is focused on the adequacy of present maintenance practices and hardware to ensure a safe working environment. Work procedures[9] have been developed for both energized (live line) and de-energized (dead line) maintenance practices.

For de-energized line work, there are six basic safety steps: notification, certification, switching, tagging, testing, and grounding. When work is performed on energized systems, insulating devices such as rubber gloves and mats, insulating stools and platforms, and/or insulated tools such as hotsticks are used by utility personnel. Guidelines of the Occupational Safety and Health Administration (OSHA) require that utility personnel may not approach or take a conductive object without suitable insulation. The addition of a DSG device has the potential of converting a dead line to a live line without knowledge of the maintenance person. The easiest way to prevent this situation is to either place a manual disconnect at the DSG or use live line maintenance practices where DSGs are present.

Power Conditioning

For wind and photovoltaic generators, the PCS is perhaps the most crucial link in the interconnection apparatus. Early PCS and many low cost systems consisted of inverters which often produced many harmonics and operated at low conversion efficiencies. However, recently there have been a number of important advances in development of PCS technologies. These new technologies use a method called high-frequency modulation (HFM) to chop the dc output into the sine wave pattern of ac power, using solid-state switching devices.[10] Such equipment generally produces fewer harmonics; has higher efficiencies and power factors; increased fault and reclosing detection; and improved voltage regulation compared to earlier, line-commutated designs.[11]

Working with utilities, private PCS manufacturers and government researchers at Sandia Laboratory have developed and improved upon residential-sized (< 20 kW) "advanced-design" PCS. A prototype Sandia-designed HFM-PCS performed well in utility simulator tests.[12] Further research is underway at several utilities, such as at Georgia Power (see box 6B). Most engineers agree that the HFM-PC has superior performance compared to earlier line-commutated inverters in terms of power quality. For example, current HFM devices in production (for 2 to 4 kW generators) produce harmonics similar to those of hair blowdryers, and have power factors between 0.97 and 1.00. The new equipment has fast and reliable reclosing and fault detection capabilities, accomplished through electronic sensing and control. In the case where a fault (e.g., precipitated by a thunderstorm) disconnects the PCS from a utility, logic and control circuits turn off the PCS, thus preventing any danger to the utility and any reconnection of the DSG if the utility quickly returns on-line.[13]

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[9] D.T. Rizy, et al., *Operational and Design Considerations for Electric Distribution Systems With Dispersed Storage and Generation (DSG)* (Oak Ridge, TN: Oak Ridge National Laboratory, September 1984), ORNL/CON-134.

[10] J. Stevens and and T. Key, *Draft Report: The Utility Interface—Can State-of-the-Art Power Conditioners Alleviate Our Concerns* (Albuquerque, NM: Sandia National Laboratories, 1984).

[11] Critics, however, argue that the new technology isn't necessary. For example, simulation models at the University of Texas using the Gemini inverter, a line-commutated device, show that a high penetration of photovoltaic arrays on two different types of distribution feeders does not significantly influence power quality. With 20 percent penetration of a particular feeder, there is less than 1 percent of total harmonic distortion of voltage, the power factor remains between 0.7 and 1.0. The models indicate that there is no problem with DC injection into the AC circuits since the amount of time required for DC to be injected (after the failure of the Gemini inverter) into the grid is much greater than the amount of time needed to detect the DC injected and isolate the fault. Voltage drops experienced were less than 0.3 percent with 30 percent PV penetration; see J. Fitzer, et al., University of Texas at Arlington, *Impact of Residential Utility Interactive Photovoltaic Power Systems on the Utility*, contractor report to Sandia National Laboratories, Albuquerque, NM, March 1984.

[12] Stevens and Key, op. cit., 1984; and W. I. Bower, et al., "Photovoltaic Power-Conditioning Performance Evaluation: Lessons Learned," paper presented at IEEE Photovoltaic Specialists Conference, May 1984.

[13] T.S. Key, "Evaluation of Grid-Connected Inverter Power Systems: The Utility Interface," *IEEE Transactions on Industrial Appli-*

Box 6B.—Georgia Power & Light Co.

Encouraged by the provisions of PURPA, entrepreneurs in Georgia are renovating many of the small textile mills which were abandoned over the past several decades. The renovation has been spurred on just for the sake of producing power from the under 5-MW hydroelectric plants that were once part of the mills. Over 35 mills have been refurbished, and Georgia Power & Light receives at least two applications a month for new ones.

The utility has over 600 MW of DSG capacity, which represents about 5 percent of its system peak load. The units are all fairly large and use conventional technology, ranging in size from a 750-kW hydro plant to a large 70-MW wood-waste steam turbine cogenerator. Even with this profile of DSGs, the utility has not experienced any reduction in power quality or other problems with the units, and has had no complaints from non-DSG customers.

However, Georgia Power is continuing to push the interconnection technology forward and it is one of the four participating utilities in the Sandia Laboratories project to test the new high-frequency PCSs in "real world" situations. Using an instrumented test facility in Florida, the utility will test the high-frequency modulation PCS technology on a series of three residences with 5-kW photovoltaic arrays. The homes are on a standard 13.8 kV distribution line. Georgia Power will test the power quality of the PCS with and without conventional generation on the line as well as with and without extra capacitors to boost power factors.

Sandia has also asked Georgia Power to test the injection of DC current directly into the transformers, thus simulating the failure of a PCS as closely as possible.

SOURCE: Clayton Griffith, Georgia Power & Light Co., personal communication, July 1984.

This increased PC performance, however, comes at a premium price. If HFM devices were required by utilities, the increase in price would burden the smallest generating customer. (See figure 6-3 in next section for cost comparisons of different sized interconnection equipment.) One suggested alternative is to institute varying requirements for different sizes and types of generators. Utilities have begun to use this idea in their own guidelines for interconnection (as discussed in the next section) by having different sections of the guidelines apply toward a particular size of generator.

Some utilities are still concerned about the so-called "pollution" of their power systems, while others consider this concern as overly restrictive. Some researchers believe that if non-DSG customers cannot distinguish differences in power quality, the utility should not penalize DSG customers with overly stringent and costly requirements.[14] This would shift the issue of "how high a power quality is appropriate" to the question "what are customers willing to pay to receive higher power quality?" These issues are being debated in the technical community.

Metering

The third and last component of interconnection is the metering equipment used to measure power consumed by the customer. In general, the three types of meters available today are the single watt-hour, double watt-hour with rachets, and advanced meters.[15] The single watt-hour meter is in common use in most homes and costs about $30 (1984$). If a DSG is producing power, the meter simply runs backward. This configuration only measures net power use and assumes that there is no difference between the utility's retail rates and its rate for purchasing power from DSGs. If these rates are different, which is usually the case, then two meters are routinely used, one of which runs in the reverse direction to measure power produced; both meters have rachets that prevent any reverse rotation. Another configuration uses more advanced meters to

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cation, July/August 1984' and R.S. Das, et al., "Utility-Interactive Photovoltaic Power Conditioners: Effects of Transformerless Design and DC Injection," paper presented at Intersociety Energy Conversion Engineering Conference, No. 849413, August 1984.

[14] Martin Schlect, General Electric Co., personal communication, July 1984.

[15] Discussed in more detail in OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

measure such quantities as power factor, energy, and time of use.

One metering issue is the incremental expense of additional metering for DSG customers: should the DSG customer be required to purchase meters that a non-DSG customer is not required to have? For example, Wisconsin Power & Light does not require those customers who did not previously use time-of-day meters to install them when interconnecting their DSGs.[16] Another metering issue centers around when and how DSGs should be charged for consuming reactive power.

Summary

The current evidence suggests that the technical issues of interconnection can be resolved and that state-of-the-art power conditioners can alleviate many utility concerns about the quality of interconnection subsystems. Advances in automation in electric systems will tend to mitigate many problems associated with DSGs.[17]

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[16] Wisconsin Power & Light Co., "Various Guidelines for Parallel Generation," Madison, WI, September 1983; and B. Bauman and D. Fimreite, "Parallel Generation in Southern Wisconsin," paper presented at the Summer Meeting of the American Society of Agricultural Engineers, No. 80-3041, June 1980.

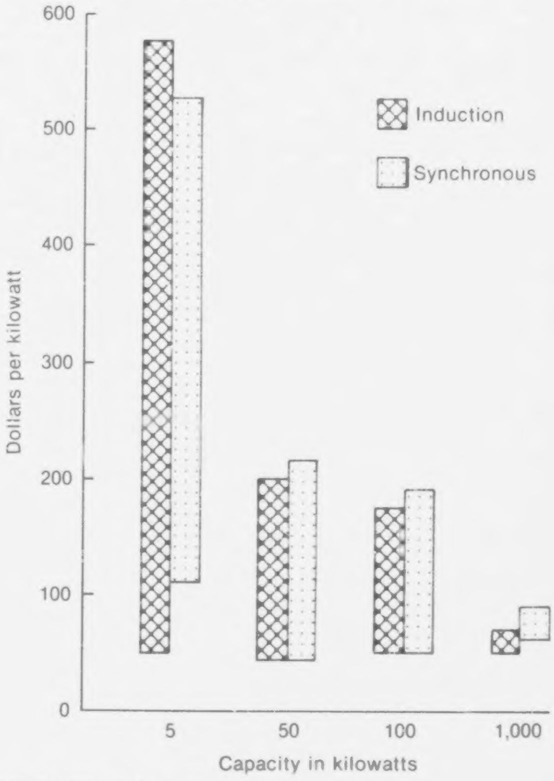
[17] D.T. Rizy, et al., *Operational and Design Considerations for Electric Distribution Systems with Dispersed Storage and Generation (DSG)*, 1984.

INTERCONNECTION COSTS

Recent research demonstrates that costs for interconnection per kilowatt decrease rapidly as generator size increases. Moreover, costs have come down dramatically[18] for the smaller generators in recent years and are now within $600/kW for the 5 kW (residential) size and $200/kW for 50 kW size.[19] (In 1983, OTA reported costs of interconnection equipment vary between $12/kW for larger generators to $1,300/kW for smaller generators.[20])

Figure 6-3 shows the range of costs for both induction and synchronous DSGs, based on typical configurations for seven generator sizes and

Figure 6-3.—Costs for Interconnection of Qualifying Facilities



SOURCE: Office of Technology Assessment

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[18] For example, Janice Hamrin (Executive Director, Independent Power Producers Association) indicates that Pacific Gas & Electric opened its bidding process for interconnection equipment in mid-1984 and this has tended to drive down the costs of interconnection (OTA Electric Utility Advisory Panel, August 1984).

[19] H. Geller, Self-Reliance, Inc., "The Interconnection of Cogenerators and Small Power Producers to a Utility System," contractor report to the District of Columbia Office of the People's Counsel, Washington, DC, February 1982; T.S. Key, "Power Conditioning for Grid-Connected PV Systems Less Than 250 kW," paper presented at Intersociety Energy Conversion Engineering Conference, No. 849407, August 1984; P. Wood, "Central Station Advanced Power Conditioning: Technology, Utility Interface, and Performance," paper presented at Intersociety Energy Conversion Engineering Conference, No. 849411, August 1984; D. Curtice and J. B. Patton, Systems Control Inc., *Interconnecting DC Energy Systems: Responses to Technical Issues*, contractor report (Palo Alto, CA: Electric Power Research Institute, June 1983), EPRI AP/EM-3124.

[20] OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

two levels of protection, using manufacturers information and price catalogs currently available. For the higher level of protection, additional interconnection equipment is used, such as dedicated transformers, more expensive "utility grade" (see box 6A) relays, and more protection devices.

Interconnection costs include engineering labor and the equipment cost of switchgear, power transformers, instrument transformers. For installations under 50 kW, these costs can be prohibitive when using utility-grade equipment and providing the typical level of protection for generating equipment. (Many of the details of interconnecting DSGs have been tabulated elsewhere.[21]) These costs are still much higher than the Department of Energy's (DOE) suggested price of $200 to $300/kW for "economical" interconnection equipment for residential generators.[22] While future technological advances such as microprocessor controls, less costly nonmetallic construction, and integration of different components could bring prices down, "the major cost decrease is expected to come from volume production" of interconnection equipment.[23]

For systems using inverters, perhaps the most costly component for interconnection is the power conditioning subsystem (PCS). In 1981, Sandia Laboratories asked four potential PCS manufacturers to estimate their selling price for these units, assuming they would be sold in quantity lots of 1,000. The prices ranged from $109 to $254/kW for 100 kW-sized units. Since receiving these estimates, Sandia reports that the cost of solid-state power devices has fallen dramatically and predicts that prices will drop substantially in the future.[24]

Interconnection costs have continued to decline during the past 5 years. However, the cost of interconnection for smaller units remains a high proportion of the cost of the generation equipment ($600/kW). The cost for interconnection for larger units is about 5 to 10 percent of the capital cost of these units.

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[21] D.T. Rizy, *Protection and Safety Requirements for Electric Distribution Systems With Dispersed Storage and Generation (DSG)* (Oak Ridge, TN; Oak Ridge National Laboratory, August 1984), ORNL/CON-143.

[22] Stevens and Key, op. cit., 1984.

[23] T.S. Key, "Power Conditioning for Grid-Connected PV Systems Less Than 250 kW," op. cit., 1984.

[24] D. Chu and T.S. Key, "Assessment of Power Conditioning for Photovoltaic Central Power Stations," paper presented at IEEE Photovoltaic Specialist Conference, May 1984.

UTILITY INTERCONNECTION STANDARDS

In the first years since the enactment of PURPA, few utilities had any published guidelines dealing with interconnection requirements. In 1983, OTA reported that most interconnection configurations were custom-fitted and no general patterns for utility standards had emerged.[25] Since 1983, the number of applications from dispersed generating customers to interconnect to utilities has increased. As a result, more utilities have standardized their interconnection requirements in the form of published guidelines. The guidelines, approved by the Public Service Commission, usually require data and drawings on the type of generator and PC equipment as well as anticipated customer loads.

It is important that such requirements be sensitive to the needs of both the utility and DSG customers. The customer should know exactly what equipment is necessary so that costs can be predicted with some certainty, and the utility should be able to reduce design review approval time and costs so that its power quality and operations can be maintained. Knowing probable interconnection costs ahead of time may be as important as the actual cost itself.[26]

Interconnection guidelines should also stimulate the exchange of information between the utility and the DSG customer. Ideally, the DSG customer should have access to necessary information regarding technical characteristics of the utility system's power circuits, such as relay tolerance settings, the short circuit capacity at the point of interconnection, and the speed and operation of reclosers after detecting faults.

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[25] OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

[26] F.V. Strnisa, et al., New York State Energy Research and Development Administration, "Interconnection Requirements in New York State," paper presented at Tenth Energy Technology Conference, Washington, DC, 1983.

Utilities currently use two different philosophies in preparing guidelines: they either prescribe functional performance requirements that must be met by the interconnection equipment, or nonfunctional, equipment-specific requirements. For example, a utility might require equipment to detect when the DSG generates power with a frequency outside a certain range (a functional requirement) or require specifically an underfrequency relay (technology-specific).

While a combined approach may be used by a utility in preparing its guidelines, research to date suggests that performance-based standards appear preferable since they allow cogenerators to meet functional criteria rather than requiring them to install particular types of equipment that might later be found unnecessary. New interconnection equipment is being introduced continually with better performance and reduced cost. Perhaps in response to the fast pace of technological change and improvements in the dispersed generation industry, many utilities are instituting function-based interconnection guidelines.

Typically, utilities have different requirements for different sized DSGs, with fewer and less stringent protective functions for the smaller generators. While the precise definition of "smaller" versus "larger" is not agreed upon by all utilities, usually, generators less than 20 kW are considered small DSGs and have fewer functional requirements imposed on them than generators larger than 100 kW. The rationale behind this scaling is, as mentioned earlier, to relate the level of protection and cost of the interconnection equipment to the size of the generator. In spite of this, the per-kilowatt cost of even the least stringent interconnection requirements is much higher for smaller generators (see figure 6-3.)

There are other variations in the exact requirements specified by utility guidelines (see box 6C). Even within a particular State, such as New York, requirements differ among utilities for particular kinds of equipment, compliance with specific electrical codes, etc.[27] (see table 6-2 and box 6D).

In addition to these changes, there are the ongoing efforts by standard-setting committees of the Institute of Electrical and Electronics Engineers (IEEE) and the National Electric Code (NEC) as well as research sponsored by DOE, and the Electric Power Research Institute (EPRI) to develop national "model" guidelines. While all of these organizations have published draft standards or suggestions for model guidelines, none has as yet released final versions.[28] One of the more influential of such efforts is the preparation of revisions to the NEC. Working groups meet periodically to suggest revisions, and the overall committee publishes the consensus every 3 years, with the next revision planned for 1987. Once the revisions are published, they are usually circulated to all local city, county, and other municipal bodies, which then incorporate the changes into their own local building and inspection codes. This process of incorporation, however, may take a decade or longer.

The delays inherent in this process work against the fast-changing nature of interconnection technology. Even with the adoption of NEC or other national standards, utilities are reluctant to accept equipment which is unknown to their own experience, even if it is in wide use in some other utility's service territory. For example, New York State Electric & Gas requires that interconnection equipment meet American National Standards Institute standard C37.90 (for power quality) but stipulates the utility must have already tested the equipment, surveyed users by telephone, and collected successful performance histories in other utilities.[29]

Another example is the requirement that DSG customers use "utility-grade" relays, which cost

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[27] Ibid.

[28] S. Chalmers, "Status Report of Standards Development for Photovoltaic Systems Utility Interface,"paper presented at Intersociety Energy Conversion Engineering Conference, No. 849406, August 1984; IEEE Standards Coordinating Committee for Photovoltaics, "Terrestrial Photovoltaic System Utility Interface for Residential and Intermediate Applications,"Standard 929 (Draft), November 1983; and D. Curtice and J. B. Patton, *Interconnecting DC Energy Systems: Responses to Technical Issues*, op. cit., 1983.

[29] F.V. Strnisa, et al., "Interconnection Requirements in New York State," op. cit., 1983.

Box 6C.—The Evolution of Utility Guidelines

Interconnection guidelines have been evolving for two reasons: the increase in number of customers applying for interconnection, and the increase in utility engineering experience. However, this evolution has not been consistent across utilities: some utilities have made their guidelines more restrictive, while others have become more liberal. The final implications are that guidelines are vastly different among utilities.

An example of one utility that has liberalized its guidelines is Southern California Edison (SCE). SCE was one of the first utilities to publish interconnection guidelines. Since then over 400 MW of dispersed generation has been installed on its system. The original set of guidelines was the product of the utility's own experience and research and has not changed significantly since its inception. However, recent experience has shown that underfrequency detection has been too stringent when the operation of the interconnection equipment is compared to the normal variations in the centralized power supply for large industrial customers. As a consequence of this frequency range, the present interconnection devices have tripped these customers off-line when small disturbances or short circuits have reduced overall system frequency. SCE has revised its guidelines to allow a greater underfrequency operating range so that the interconnection devices will continue to keep these larger customers on-line.[1]

By contrast, another utility, Wisconsin Power & Light (WP&L), has recently made its guidelines more stringent. Between 1980 and 1983, WP&L's guidelines underwent substantial revision based on analysis of both interconnection economics and experience. The 1980 guidelines split DSG customers into two classes by generator size: those with generation under and those exceeding 200 kW, respectively. The 200 kW threshold was lowered in 1983 to 20 kW.

Originally, the 1980 buy-back rates for less than 200 kW customers were 4.8 cents/kWh on-peak and 1.75 cents/kWh off-peak. Larger generating customers were required to negotiate their rates on an individual basis with WP&L. In 1983 this requirement was revised: customers with generation less than 20 kW are billed on a net-energy basis, thereby eliminating the need for time-of-day metering (if the customer did not originally use one) and providing a higher buy-back rate. Customers with generation greater than 20 kW are paid depending on the location of their interconnection to the WP&L system—either at the transmission, distribution, or secondary distribution level—but the on-peak rate is less than 4 cents/kWh and the off-peak rate is more than 2 cents/kWh.

In 1983 a liability clause was added requiring all generating customers to maintain $100,000 of insurance "or demonstrate financial responsibility satisfactory to [WP&L]." This clause is unusual, as many utility guidelines do not even mention any special liability coverage.[2]

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[1] A. Dawson, Southern California Edison, personal communication, May 1984.

[2] Guidelines provided to OTA by Virginia Electric Power Co., Wisconsin Power & Light Co., and Carolina Power & Light Co.; Carl DeWinkel, Wisconsin Power & Light Co., personal communication, June 1984.

more and have supposedly better reliability than ordinary commercial-grade relays. There is no general agreement as to what relays are of which grade. For example, Central Hudson Electric & Gas defines relays as "utility-grade" if the utility has had experience with it and can predict its performance.[30] As yet, however, no utility has published any assessments linking reliability with the level of equipment grade. Thus, the requirement of and definition of "utility-grade" equipment may be largely attributed to general utility conservatism towards equipment performance, rather than towards specific groups of interconnection apparatus.

Equipment grade stipulations can present an awkward situation for DSG customers wishing to interconnect. For example, a utility refuses to approve an interconnection unless the equipment has undergone prior safety inspection, yet the

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[30] Ibid.

Table 6-2.—New York Utility Interconnection Requirements

	Utility						
Requirement	A	B	C	D	E	F	G
Utility approval prior to operation	X	X	X	X	X	X	X
Utility inspection	X	X	X	X	X	X	X
On premise maintenance log	X	X	X	X		X	X
Lockable manual disconnect switch	X	X	X	X	X	X	X
DSG shall not energize a dead circuit	X	X	X	X	X	X	X
Harmonic content limit	X	X	X	X	X	X	X
Reactive power meter			X				
Protective equipment including:							
Main circuit breaker	X		X	X		X	
Power transformers for isolation	X		X				
Automatic fault detection and shutdown equipment		X	X	X	X	X	X
Dead circuit detection equipment		X	X		X	X	
Over/under frequency and voltage relays		X	X				
Directional overcurrent relays		X					
Ground overcurrent relays		X		X			
Synchronizing equipment				X		X	
Conform to the applicable codes including:							
National Electric Code		X	X		X		X
National Electric Safety Code			X				
Fire Underwriters			X		X		
UL approval						X	
DSG may not backfeed power to secondary networks	X						

KEY TO UTILITIES:
A. Consolidated Edison Co.
B. Central Hudson Gas & Electric Corp.
C. Long Island Lighting Co.
D. New York State Electric & Gas Corp.
E. Niagara Mohawk Power Corp.
F. Orange & Rockland Utilities
G. Rochester Gas & Electric Co.

SOURCE: D. Wolcott and F. Strnisa, *New York State Interconnection Issues Manual* (Albany, NY: New York State Energy Research and Development Authority, March 1984).

safety inspectors have refused to approve the installation of interconnection equipment unless they have prior utility consent. An example of this dilemma is the case of a wind generator control panel, which several utilities insist must have Underwriter's Laboratories (UL) approval. UL, however, does not test assembled control panels, although they do test the components used in the panels. Such subtleties can create significant delays in granting interconnection approval, increase the cost both to the utility and the customer. In such instances, some experts argue that:

> . . . the burden of proof for refusing to accept a relay that has passed the standard tests [should] be placed on the utilities. [The utility should ei-

Box 6D.—Consolidated Edison Co. (ConEd)

The service area for ConEd contains all of New York City and parts of Westchester County. The combination of high cost for electricity, many older plants, and dense population have made the area ripe for potential DSG opportunities. Yet, the difference between opportunity and installed DSG capacity is large—so far only one 40 MW cogenerator has been allowed to interconnect to ConEd's network, while 30 applications are still pending. The chief cause of this disparity is due to the different expectations and interpretations of responsibility between potential DSG customers and the utility.

ConEd's interconnection guidelines delineate the precise responsibility of the potential DSG customer in obtaining an interconnection, the engineering considerations, and the data that the customer must supply to ConEd with the application. Some DSG applicants claim that these guidelines are too stringent for any economical interconnection, while the utility counters these criticisms by saying that the cost for interconnection is higher due to the network configuration of its transmission and distribution (T&D) system within Manhattan, and that the detailed guidelines are necessary for the proper operation of its T&D system.

ConEd argues that Manhattan network has a different topology from that of other utilities around the country. Rather than a radial, hub-and-spoke type of pattern (as shown in figure 6-1), the Manhattan network is a criss-cross grid with many intersecting nodes between distribution lines. In a radial system each customer has one centralized source of electricity supply, and if that source goes out of service, the customer is without power. In the network system, each customer has multiple sources of centralized supply. At many places in ConEd's Manhattan network certain types of protective devices are placed to allow power to flow from source to customer and not in the reverse direction. Because of this, if DSGs were placed at the customer site, power could not be fed back into the grid and a critical benefit, that of sales of power back to the utility, would not be possible.

SOURCE: Roch Cappelli, Consolidated Edison Co., personal communication, August 1984; and Bill Wagers, Consolidated Edison Co., personal communication, May and August 1984.

> ther be required to] show negative operating system experience, or they must develop a testing program . . . rapidly and systematically. . . . If one utility tests relays and finds them acceptable the results should [constitute compelling evidence for other utilities].[31]

Therefore, due to a combination of utility conservatism, jurisdictional issues, marked differences in individual utility's guidelines, and the lack of model national standards, DSG customers are likely to face a confusing array of interconnection guidelines well into the next decade. The extreme diversity among utility guidelines may also make it difficult to produce high volumes of standardized equipment and to achieve accompanying economies of scale. All of these factors may slow the deployment of DSGs.

UTILITY SYSTEM PLANNING AND OPERATING ISSUES

Overview

The process of planning and operating an electric utility system is a very complex one. *Planning* focuses on the selection of technology requirements (generation, transmission, and distribution) to satisfy predicted demand by the most financially attractive means. *Operations management* refers to the day-to-day, hour-to-hour, and second-to-second deployment of existing facilities to meet the demand on the electric system. Both processes have an overriding goal: to provide the production and delivery capabilities to meet electricity demand in a safe, reliable, and economic manner.

The addition of DSGs to the utility network complicates both planning and operations. In the short-term, if utility system controllers do not correctly anticipate load changes, network elements (transformer, lines, generators, etc.) may become overloaded and circuit breakers may open, possibly causing power reductions or interruptions for customers. In the medium-term, insufficient transmission and distribution capacity may cause poor quality of service. And over the long term, if utility planners underestimate or overestimate future demands, the utility may be placed in financial jeopardy by having to purchase power from its neighbors at high rates (for underbuilding) or by having too much idle capacity (for overbuilding). This section discusses the effect of increasing DSG capacity on utility operations and planning.

Electric System Planning

Good planning of electric systems is the key to controlling costs since the timing and type of additions will likely determine overall costs. There are two components in the electric supply cost equation: fixed or capital costs, and variable costs, e.g., fuel, operation, and maintenance. Although the overall cost tends to be dominated by generation costs, on the order 60 to 65 percent, transmission and distribution costs cannot be ignored. The greatest impact of DSGs is likely to be on the distribution system itself.

Determining DSG's impact on the overall electric system involves: 1) estimating the performance of the DSG, 2) establishing the relationship between system load and DSG performance, and 3) calculating the change in the utility's performance resulting from the DSG.[32]

Generation System Planning.—As discussed in chapter 3, utilities perform fundamental economic studies of their systems so that the most financially attractive generation option can be chosen to meet predicted demand and so that they can determine when to retire existing units. The basic calculation involves the estimation of the value resulting from the installation of a power source—defined as the savings in conventional fuel, operation, maintenance, and capacity costs.

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[31] Strnisa, et al., op. cit., 1983.

[32] T. Flaim, et al., *Economic Assessments of Intermittent, Grid-Connected Solar Electric Technologies: A Review of Methods* (Golden, CO: Solar Energy Research Institute, September 1981), SERI/TR-353-474.

A number of value studies of incorporating solar energy generating sources into utility resource plans have been performed on a variety of specific utility systems since 1975.[33] Typically, these studies analyze a base case (without solar technologies) and then a case with solar. The value assigned to the solar energy is the cost difference between the two study cases.

These studies[34] generally incorporate the following steps in evaluating the value of DSGs in a utility's resource plan. First, a base case analysis of an expansion plan without solar technology establishes a benchmark against which solar technologies are evaluated. Next, a second case is analyzed with solar technologies in three steps: 1) estimating the power output of the solar technologies, 2) modification of the hourly loads by the solar production to determine the residual hourly loads on the nonsolar technologies generation, and 3) recalculating production costs and the reliability impacts. Typically, generation planning studies for the 20- to 30-year planning horizon do not use detailed, hourly data, but the intermittent nature of solar energy requires this type of representation. The difference in reliability between the base case and the solar alternative can be used to compute the solar technologies' capacity credit in the utility's generation plan. As a final step in the process, the cost difference between the cases with and without solar technologies are examined to obtain the single year savings. Using the single year savings, the present value of the total savings is accumulated over the expected lifetime of the solar facility under study.

The most important factor affecting the breakeven energy cost is the utility's present and planned future generation mix, which determines the type and quantity of fuel and capacity displaced. Evidence strongly suggests that while solar technologies may displace some conventional production capacity, the greatest value of solar rests with the displacement of energy, i.e., fuel savings.

Key areas of future work include the development and validation of models that accurately characterize the dynamic behavior of solar technologies. Capacity potential will be measured in part by the effectiveness of solar technologies to participate in short-term load following process, i.e., load frequency control.

Transmission Planning.—Electric transmission systems are studied in terms of network capacity and reliability requirements. Criteria for sizing the transmission system vary from utility to utility; however, the basic purpose of all transmission system design studies is to establish when and where new lines should be added and at what voltage level.

A transmission plan consists of three major components: 1) a generation dispatch strategy and the projected load profile for the system are used to determine the expected transmission line loading levels over the planning period; 2) a minimum cost transmission expansion plan for the horizon year which meets the reliability criteria; and 3) and a "through-time plan," i.e., the sequence of changes in the transmission system in transition to the horizon year.[35] Key parameters for comparing alternative expansion plans are the number of line additions required per unit of time and the present worth cost of those additions.

Studies sponsored by EPRI[36] estimate transmission "credits," i.e., capital cost savings, associated with DSG siting close to load centers of $66 to $133/kW, for a variety of transmission system configurations. If more expensive underground cables are involved, the savings were estimated to be as high as $250/kW. The simulations showed that an optimal DSG market penetration, from the point of view of transmission system planning, appeared to be about 20 percent of metropolitan load growth. Below or above that level, the transmission credits per kilowatt decreased.

Distribution Planning.—The effect of DSGs on the distribution system (typically 13 kilovolts and below) is determined by the deployment strategy of the equipment. Clusters of generating equipment, irrespective of individual unit size, that are placed on feeders or in substations, affect the system very differently than small generators distributed throughout the electric system.

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[33] Ibid.; and T. Flaim and S. Hock, *Wind Energy Systems for Electric Utilities: A Synthesis of Value Studies* (Golden, CO: Solar Energy Research Institute, May 1984), SERI/TR-211-2318.

[34] T. Flaim and S. Hock, *Wind Energy Systems for Electric Utilities: A Synthesis of Value Studies*, op. cit., 1984.

[35] B. M. Kaupang, *Assessment of Distributed Wind Power Systems* (Palo Alto, CA: Electric Power Research Institute, February 1983), EPRI AP-2882.

[36] Systems Control, Inc., *Impact on Transmission Requirements of Dispersed Storage and Generation* (Palo Alto, CA: Electric Power Research Institute, December 1979), EPRI EM-1192.

In substations, the primary element for concern is the transformer. The addition of DSGs has the potential for changing significantly the operating conditions of the transformer. Deferring additional substation capacity is the desirable attribute. For small additions of DSGs up to some minimum level, no deferral of transformer capacity results because the substation is largely responsible for serving all the load. Above this minimum up to some maximum level, deferrals will result; above the maximum, additional transformer capacity is required for the generator itself. In sum, the effect of deferral is captured by the particular sizing policy of the utility, but DSGs can defer the addition of both transformer and feeder capacity.[37]

The addition of DSGs to the substation has no influence on distribution system losses, but placing generating equipment on the feeder can reduce losses because the production will be closer to the load. When generation is placed closer to the load, less power is transported through the system, thereby reducing losses. DSG installation must be well planned so that existing circuits are not a limitation. Again, the amount of loss reduction depends on the utility.

Excessive voltage fluctuations offer greater potential concern when DSGs are placed in the distribution system, especially since they are nearer the loads. Under wind gust or cloud cover conditions, solar technologies can cause large voltage swings due to current surges from the electrical converter. Voltage regulators and tap-changing transformers in the power system are very slow to respond (on the order of a minute) resulting in no influence on the short-term problem.

Electric Power Systems Operations

Overall management of power system operation consist of two phases—operation planning and real-time operation. Operation planning consists of the scheduling of generation and transmission facilities for use during a 1- to 3-day period; it is the so called "predispatch problem." Real-time operation involves the on-line management and control of all facilities on a second-to-second basis. In most utilities, daily operations are directed from a central control center.[38]

Operations Planning.—A strategy is formulated to deploy the system's available resources to meet the anticipated load of the next day economically and reliably. First a load forecast of hourly loads and load ramp rates (minute to minute changes in load) is made to determine the generation and transmission requirements. Subsequently, a "unit commitment" strategy is determined based on available facilities as determined by any scheduled or unscheduled down-time of equipment. The resulting plan is the guideline to daily operations.[39]

Real-Time Operations.—Utilities must continually adjust electricity production to follow the constantly changing electric demand. Production and demand are maintained in balance by the combined actions of speed governors on individual generating units (frequency regulation) and a closed loop automatic generation control system which performs load frequency control (regulation) and economic dispatch functions.[40] In addition, the instantaneous balance of load and demand is known as stability. A configuration is chosen which assures a stable system under a credible list of potential system component failures (faults, equipment trips, etc.).

Automatic Generation Control.—There remains much uncertainty and debate over what DSG penetration level will negatively affect utility system performance. An earlier OTA report[41] discusses concerns about the effects of a high penetration of DSGs. A common definition of "high penetration" is a DSG capacity over 25 percent of the capacity of the particular distribution feeder or over 25 percent of overall utility system capacity.

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[37] Ibid.

[38] T. W. Reddoch, et al., "Strategies for Minimizing Operational Impacts of Large Wind Turbine Arrays on Automatic Generation Control Systems," *Journal of Solar Engineering*, vol. 104, May 1982.

[39] Ibid.

[40] Ibid.

[41] OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

There are no utilities today approaching this definition of high penetration of DSG equipment on particular distribution feeders—even the utilities with the most DSG installations have less than one-tenth of 1 percent penetration. Yet, for most utilities, the penetration level is increasing and some, such as Houston Lighting & Power, are planning for the possibility of penetrations as high as 30 percent by the year 2000.[42] One utility in Hawaii currently has 10 percent DSG penetration (see box 6E).

The effect DSGs have on an electrical system's area control error (ACE) is of particular interest. ACE measures a combination of frequency deviation and net tie-line power flow (see box 6A). North American utilities have agreed on certain minimum standards for ACE values: ACE must equal zero at least once and must not vary beyond a certain range during each 10-minute interval.[43]

Analysts measuring utility system performance with high penetrations of DSGs must measure the increase in ACE caused by the DSGs, rather than by other influences unrelated to DSGs. These measurements are difficult to make in the field, since ACE often results from the demand shifts caused by fast-changing, unpredictable conditions such as a quickly moving thunderstorm, a fast drop in temperature, or a drop in power coming from a neighboring utility across a high-voltage tie-line.

Most researchers agree that at the present low levels and continuing up to at least 5 percent of DSG penetration, there are no ill effects on system operations as measured by ACE. However, there is no general agreement on what increase in penetration of DSGs beyond 5 percent will increase ACE.

Curtice and Patton[44] used data on wind generators and estimated ACE for four different generator penetration levels. Their results indicated that ACE increases only 1 percent when total wind capacity is at 20 percent of the overall utility system. When penetration reaches 50 percent, ACE increases to 10 percent. While these changes in ACE were not significant, the authors noted, with 5 percent penetration, wind output variations

> . . . did not cause a significant change in the control process. . . . However, increased energy flow over the tie-lines connected to neighboring utilities compensated for generator/load mismatches occurring too fast for the utility's generators to follow. If the utility's control process is designed to minimize tie-line flow deviations, . . . then generator/load mismatches show up as increased ACE and decreased system performance.

These results suggest that, although measured ACE was not large, there is a potential problem with installing wind machines. *If* there is a high enough fluctuation in wind speed, *if* there is a high proportion of wind generation on a particular feeder, and *if* the utility optimizes its control procedures for minimizing tie-line variations (an electric industry standard), a decrease in system performance could occur. Moreover, there is a potential for overloading the distribution feeder. (Other research notes the need to develop alternative generation control algorithms to better accommodate DSGs.[45])

A Sandia Laboratories study[46] also supports the view that DSGs have a limited effect on system

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[42] Henry Vadie, Houston Lighting & Power, OTA workshop on Cost and Performance of New Generating Technologies, June 1984.

[43] M. G. Thomas, et al., Arizona State University, *Draft Report: The Effect of Photovoltaic Systems on Utility Operations*, contractor report (Albuquerque, NM: Sandia National Laboratories, February 1984), SAND84-7000.

[44] D. Curtice and J. B. Patton, *Interconnecting DC Energy Systems: Responses to Technical Issues*, op. cit., 1983.

[45] S. H. Javid, et al., "A Method for Determining How to Operate and Control Wind Turbine Arrays in Utility Systems," *IEEE Transaction on Power Apparatus and Systems*, IEEE Summer Power Meeting, Seattle, WA, 1984; F. S. Ma and D. H. Curtice, "Distribution Planning and Operations With Intermittent Power Production," *IEEE Transactions on Power Apparatus and Systems*, August 1982; Systems Control, Inc., *The Effect of Distributed Power Systems on Customer Service Reliability*, contractor report (Palo Alto, CA: Electric Power Research Institute, August 1982), No. EPRI 3L-2549; and T. W. Reddoch, et al., "Strategies for Minimizing Operational Impacts of Large Wind Turbine Arrays on Automatic Generation Control Systems," op. cit., May 1982. Another recent study examined how to efficiently operate and control wind turbine arrays: see Stevens and Key, op. cit., 1984.

[46] Thomas, et al., op. cit., 1984, SAND84-7000; and M. G. Thomas and G. J. Jones, *Draft Report: Grid-Connected PV Systems: How and Where They Fit* (Albuquerque, NM: Sandia National Laboratories, 1984).

Box 6E.—Hawaii Electric Light Co. (HELCo)

The Island of Hawaii may soon have the highest proportion of dispersed electric generation capacity in the United States. Hawaii, the largest island in the State, is mostly rural and sparsely populated. The island's utility, Hawaii Electric Light Co. (HELCo), has a system peak of about 100 MW during the evening hours and a minimum off-peak demand of 40 MW. The island is not connected electrically to the other islands and has a residential electricity rate of 12 cents/kWh. The company presently has a mix of both conventional and new generation capacity: 56 MW of oil-fired steam base load generation, a 10 MW gas turbine, 24.6 MW of diesel generation, 3.3 MW of hydropower, 2.5 MW of geothermal, and 32 MW of biomass generation obtained through contracts with local sugar plantations. Finally, HELCo has signed contracts with wind developers in excess of 20 MW. This will bring the total capacity of wind turbines at HELCo to over 20 percent of the system peak load.

Due to the large number of wind machines on HELCo's system, the island utility is concerned about possible system stability problems that may result from wind farms connected at the end of long distribution feeders. During off-peak hours (11 p.m. to 4 a.m.), base load generation must be reduced to minimum levels. During these hours, wind-generated electricity fed into the grid could result in shut down of base load generation. Hence, HELCo has required all wind farms in excess of 300 kW to be equipped with supervisory controls to enable the utility to disconnect the wind farms from the system should the need arise. With many wind machines using line-commutated inverter systems, utility engineers are also concerned about excessive harmonic distortion; excessive harmonic content on the grid may create problems in other operations such as revenue metering, system losses, relaying, and quality of service.

Engineers express concern about the future operations of their utility. There is no consensus, however, about the influence of the high proportion of dispersed capacity on generation mix, power quality, and the cost and reliability of providing service. Yet, to date, there have not been any complaints from non-DSG customers about power quality, which utility personnel also feel is adequate.[1]

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[1] Alva Nakamura, Hawaii Electric Light Co., personal correspondence with OTA staff, July 11, 1985; and R.M. Belt, Hawaii Electric Light Co., personal correspondence with OTA staff, June 1984.

performance. The researchers modeled photovoltaic (PV) arrays on a long rural distribution line with 30 percent of the homes on the line using small (10 to 20 kW) PVs. In order to observe any significant increase in ACE, "a solid cloud cover would engulf all 10 miles of the distribution feeder simultaneously masking every PV home . . . and this scenario would be repeated every 6 minutes." The study maintains this is a very unlikely situation and in any event represents the worst possible condition for PV interconnection equipment.

The sudden and unpredicted loss of a large generator can drastically unbalance the supply system of a utility, especially when this generator represents a large proportion of the entire system capacity. Two modelers have studied such a situation:

Researchers from Arizona State University simulated the effects of larger PVs with a three region model (the regions are the service areas of Arizona Public Service and The Salt River Project as well as a third region representing the remainder of the Western United States and Canadian grid). A PV generator was placed in each area and its output changed in response to predetermined cloud movement and wind velocity. Five different-sized PVs were used, ranging from 50 to 250 MW. The researchers found no significant increase in ACE as long as: 1) any single central-station PV unit was less than 5 percent of total system capacity or less than 5 percent of any particular distribution feeder; and 2) a combination of smaller, home-sized PVs was less than 50 percent of total system capacity or particular feeders.[47]

Dynamics and Transient Stability.—Most concerns with stability have focused on wind turbines. The special characteristics of wind turbine generators which cause their dynamic behavior to be different from that of conventional units can be traced to the large turbine rotor diameter and slow turbine speed necessary to capture sufficient quantities of power from the relatively low power density of the wind. The electrical generators for large wind turbine applications are generally four or six pole designs and a high ratio gear box is essential to step up the low turbine speed to the synchronous speed of the generator (1,800 or 1,200 rpm). The high ratio gear box causes wind turbine drive trains to have torsional properties which are not characteristic of conventional turbine generators. But the dynamics of large wind turbines are compatible with conventional power systems and pose no apparent barrier to their application. The same could be said of the transient stability properties of wind turbines during electrical or mechanical disturbances.[48]

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[47] R. M. Belt, "Utility Scale Application of Wind Turbines," paper presented at Winter Power Meeting of the IEEE, No. CH1664, February 1981.

[48] E. N. Hinrichsen and P. J. Nolan, *Dynamics of Single- and Multi-Unit Wind Energy Conversion Plants Supplying Electric Utility Systems*, contractor report, U.S. Department of Energy (Washington, DC: National Technical Information Service, August 1981), DOE/ET/20466-78/1.

Chapter 7

Regional Differences Affecting Technology Choices for the 1990s

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Chapter 7

Regional Differences Affecting Technology Choices for the 1990s

INTRODUCTION

Overview

The inherent uncertainty associated with estimating future electricity demand is one of the most important factors affecting utility choices among electricity supply options. Demand growth rates differ dramatically within and among regions, and unanticipated changes in these rates can substantially affect both overall system reliability and the need for new generating capacity. Other factors that vary by region also strongly influence utility technology choices. This chapter focuses on these differences, quantifies them where possible, and speculates on their short- and long-term influence.

Among these other differences are plant life extension opportunities (defined by the age and type of existing generating facilities) and present and projected fuel dependence, which generally establishes regional benchmarks for technology cost comparisons. Other variables discussed in this chapter include opportunities for increased power transfers; potential supply contributions from load management, conservation, and cogeneration; constraints imposed by natural resource availability; and differences in regional regulatory and economic environments.

Definition of Regions

While regions can be defined by many characteristics—e.g., demographics, economic make-up, census divisions, and/or physical geography—the regions used most often in this chapter will be those of the electric reliability councils. There are nine regional councils in the United States and one national group: the North American Electric reliability Council (NERC). Figure 7-1 summarizes what the councils do and shows which areas of the country they cover. Figure 7-2 illustrates how these regions compare with census divisions, because occasionally data will be presented in this format as well.

REGIONAL ISSUES DEFINED BY ELECTRICITY DEMAND

The Role of Uncertainty in Regional Demand Forecasts

As noted in chapter 3, the national average annual rate of growth in electricity demand fluctuated greatly through the 1970s. Growth rate predictions have similarly varied. For example, in 1975, NERC expected demand growth to stabilize at 6.9 percent per year through 1984; as of early 1984, the council expected growth through 1993 to average 2.5 percent.[1] Other estimates range between 1 and 5 percent (see figure 3-4 in chapter 3). As figure 7-3 illustrates, small changes in expected growth lead to substantial differences in capacity requirements to meet overall demand.

Wide regional variations in demand growth rates have been and continue to be common. NERC 1984 projections for average annual demand growth in the next decade range from 1.3 (MAAC) to 4.0 percent (ERCOT). Comparable disparities also occur within regions. For example, within WSCC, which is divided into four subregions, the California-Southern Nevada Power Area expects demand growth of 1.9 percent,

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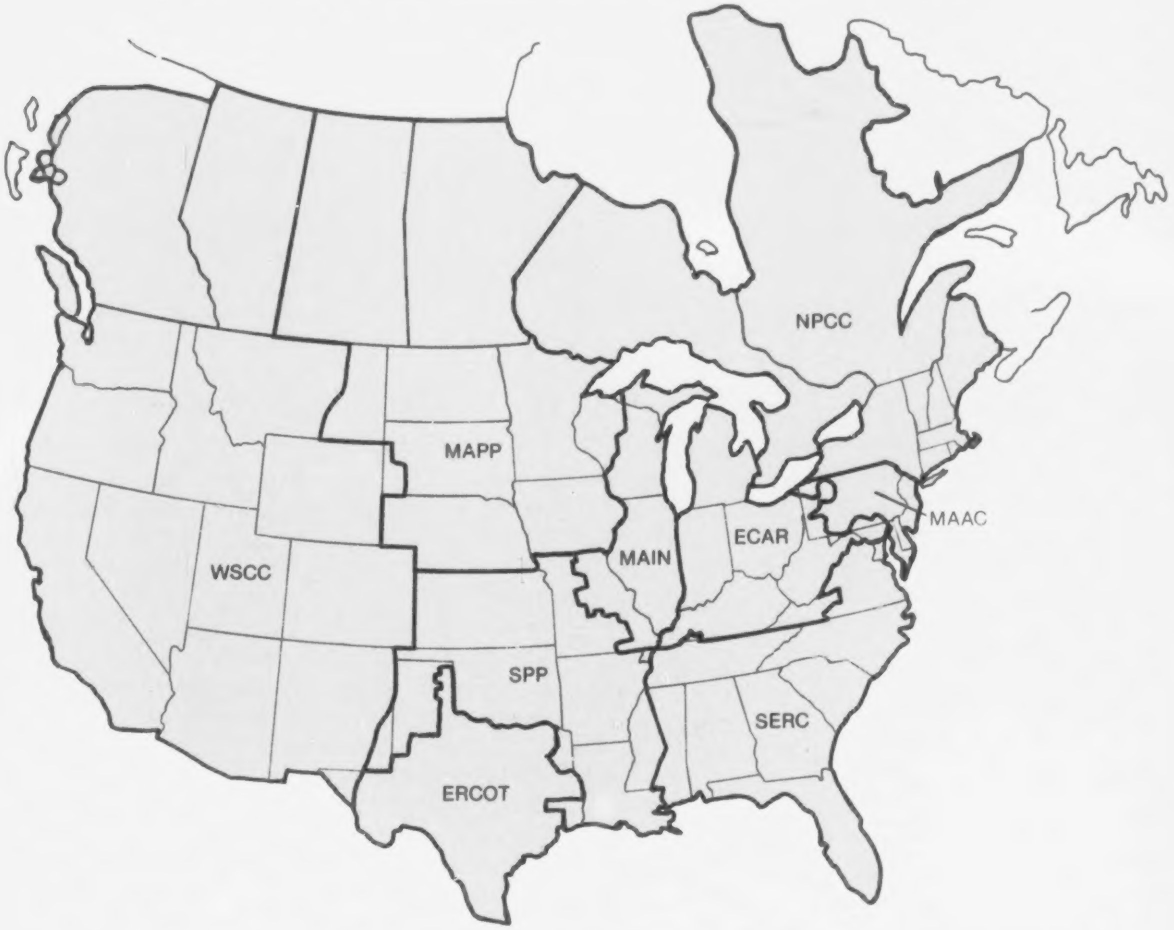
[1] North American Electric Reliability Council (NERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, 1984).

Figure 7-1.—Map of North American Electric Reliability Council (NERC) Regions

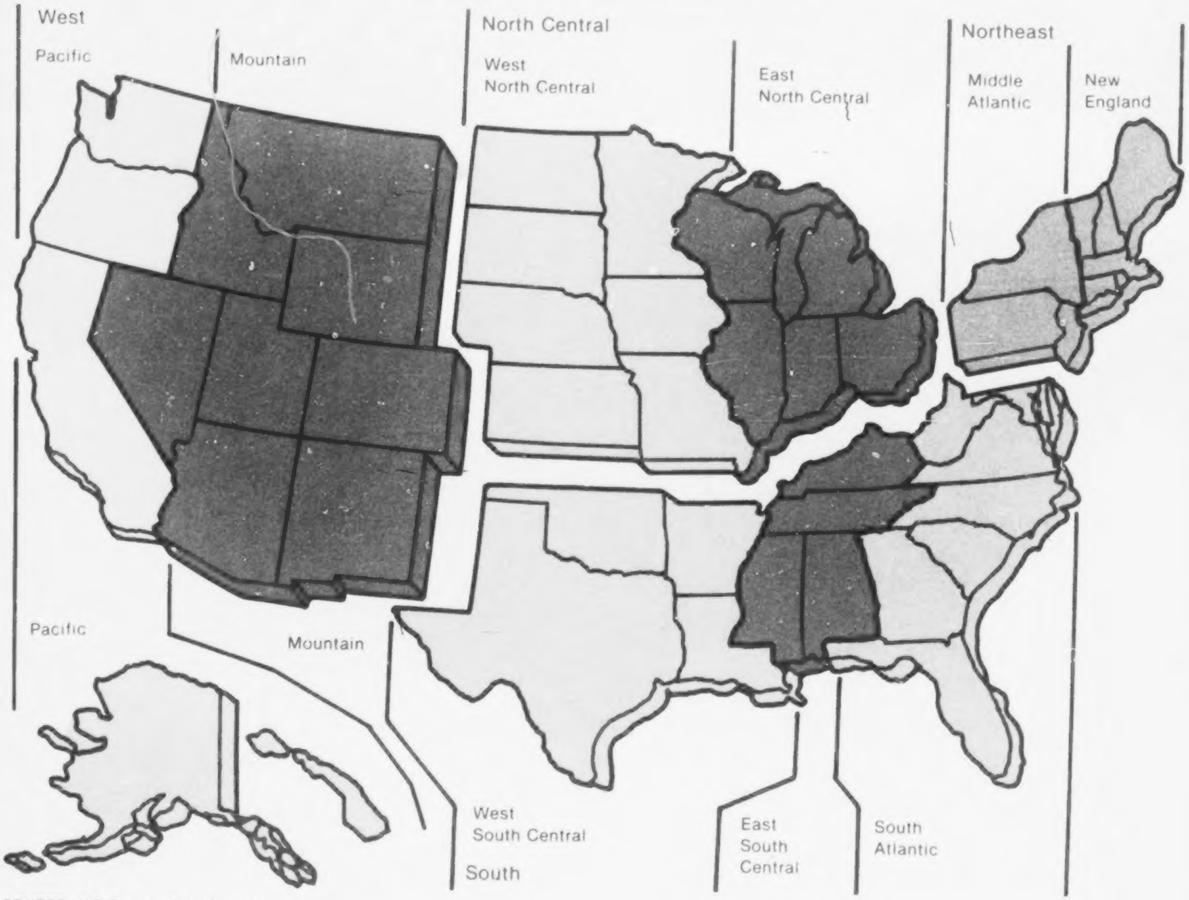


NERC helps ensure the adequacy and reliability of the U.S./Canadian electricity power supply system by acting as a forum for greater coordination between regional utility systems. The nine regional organizations listed below provide similar services to their member utilities. Several of the regional councils have member systems in Canada. Throughout this chapter, statistics will be cited for U.S. members only.

ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool Network
MAPP	Mid-continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

SOURCE: North American Electric Reliability Council (NERC), *NERC at a Glance* (Princeton, NJ: NERC, 1984).

Figure 7-2.—Map of U.S. Census Regions


West
Pacific
Mountain
North Central
West North Central
East North Central
Northeast
Middle Atlantic
New England
Pacific
Mountain
West South Central
South
East South Central
South Atlantic

SOURCE: U.S. Bureau of the Census

while the Arizona-New Mexico Power Area expects growth on the order of 4.4 percent.[2] Many factors underlie these differences in growth rates, including observed and expected consumer response to electricity prices and the prices of competing energy sources; regional and national economic structure and trends; the anticipated effects of cogeneration, load management, and conservation; varied utility system efficiency improvements; and new uses for electricity.

Historically, reserve margins have been used as general indices of system reliability. As explained in box 7A, the definition of what constitutes an adequate reserve varies. While the traditional target has been 20 percent, utility systems within the same region may adopt different standards depending on many factors, including individual plant characteristics, access to power from other systems, and characteristics of customer demand. Looking at reserve margins on a regional scale thus suggests rather than defines the reliability issues in a given region.

As figure 7-3 suggests, reserve margin estimates are particularly sensitive to demand growth predictions. U.S. Department of Energy (DOE) projections based on current NERC demand and capacity forecasts indicate that, between 1984 and 1993, six of the nine NERC regions will at some point fall short of selected reliability criteria (see table 7-4). If future demand growth proves higher

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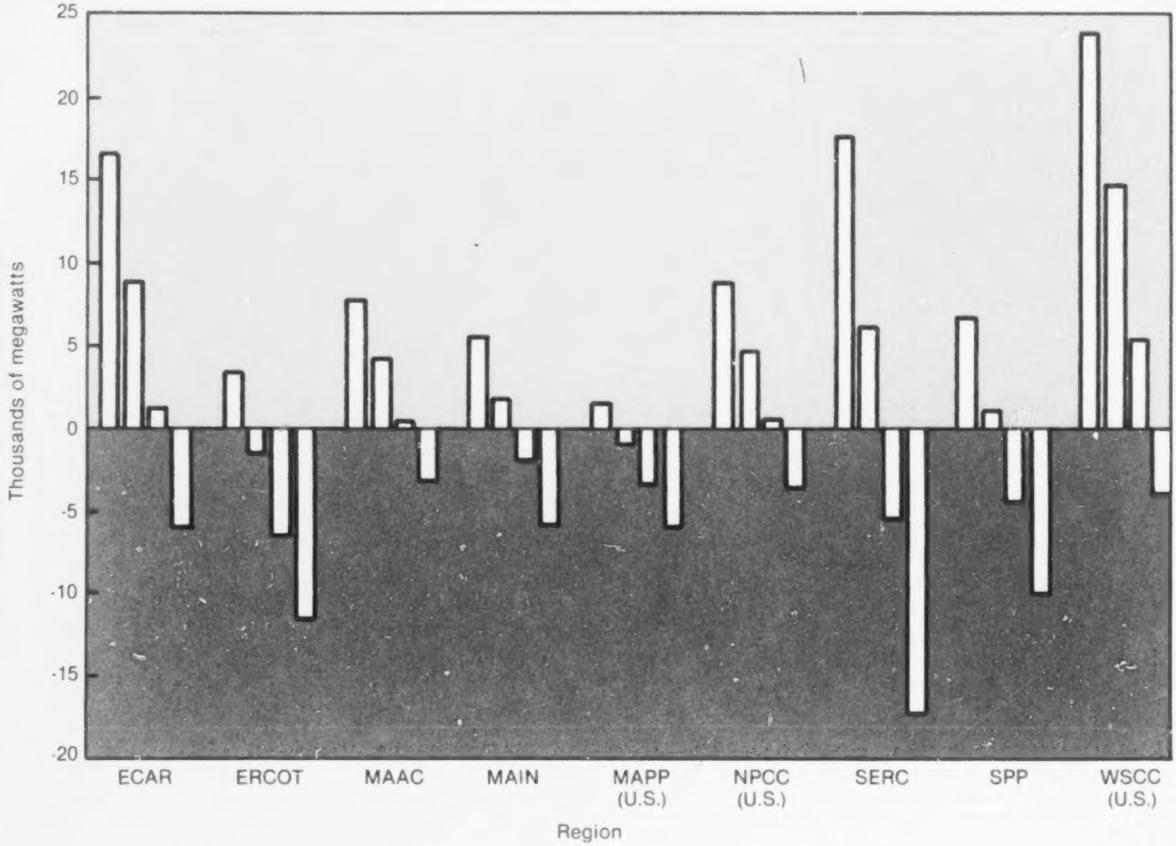
[2] Ibid.

Figure 7-3.—1993 Regional Capacity Shortfalls or Surplus Relative to 20 Percent Reserve Margin Given Varying National Demand Growth Rates and Current Utility Capacity Projections



In the figure above, regional demand is calculated under four different national demand growth rates: 1.5, 2.5, 3.5, and 4.5%.

The regional growth rates expected by NERC councils under the 1984 2.5% forecast for national demand were used to establish relative weights for each region. These weights were then applied to the three other scenarios so regional differences in growth rates would be accounted for.

The 20 percent reserve margin for 1993 was calculated with the following formula:

$$\frac{\text{capacity planned for 1993} - \text{expected peak} \times 100}{\text{expected peak}}$$

These capacity projections do not account for contributions from power interchanges, nor are they adjusted for expected maintenance, outages, and similar factors.

Shortfalls and/or excesses were calculated as follows:

$$\text{1993 planned capacity} - (\text{projected 1993 peak} + \text{20 percent reserve margin})$$

SOURCE: Office of Technology Assessment, based on data presented in North American Electric Reliability Council (NERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, 1984).

Box 7A.—Measures of System Reliability: Reserve Margins, Adjusted Reserves, and Capacity Margins

Reserve margins express the difference between demonstrated capacity and peak demand as a percent of total peak.[1] The definition of what constitutes an adequate reserve varies. For example, the Congressional Research Service[2] cites 15 percent as the lowest acceptable level and 20 percent as the optimum; the U.S. Department of Energy (DOE) sets an approximate criterion of 25 percent.[3] While the traditional target has been 20 percent, utility systems within the same region may adopt different standards depending on many factors, including individual plant characteristics (e.g., age, size, type), access to power from other systems, and characteristics of customer demand.

Two other system criteria are also used frequently: 1) adjusted reserves, which are reserve margins changed to reflect the expected impact of maintenance, forced outages, net power transactions, and other factors influencing capacity availability; and 2) capacity margins, which express the difference between demonstrated capacity and peak demand as a percent of total demonstrated capacity instead of as a percent of total peak. The recommended criterion for adjusted reserves is 5 percent.[4] No industrywide standards have been established yet for capacity margins, although the industry appears to be increasing its emphasis on this reliability measure.

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[1] Different sources calculate reserve margins differently. For example, NERC includes net capacity transfers in its definition of "demonstrated capacity"; the DOE figures cited in this chapter include net capacity transfers only in the adjusted reserve margin calculations.

[2] Alvin Kaufman and Karen K. Nelson, *Do We Really Need All Those Electric Plants?* (Washington, DC: Congressional Research Service, August 1982), Report No. 82-147 S.

[3] U.S.DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, (Washington, D.C.: DOE, June 1984), DOE/IE-0003.

[4] U.S.DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op.cit., June 1984

than anticipated, these regions—ECAR, ERCOT, MAIN, MAPP, SPP, and SERC—may risk inadequate reserve margins sometime within the next decade, unless supplies in addition to those already planned are secured.[3] This may make short lead time, modular technologies as well as accelerated conservation and load management particularly attractive to some utility systems in these areas. If, on the other hand, future demand is lower than expected, most regions will have excess reserves.

Sensitivity to changes in demand growth increases in regions where substantial numbers of new coal and nuclear plants are already under construction. The 1993 installed capacity levels in four NERC regions—ERCOT, MAIN, SERC, and SPP—are expected to exceed 1983 levels by more than 20 percent (see table 7-4). For three of these regions—ERCOT, MAIN, and SPP—this includes an increase of more than 75 percent in installed nuclear capacity. The oil-dependent NPCC will be increasing its coal capability by about 75 percent, although overall coal capability levels in the region will remain below 20 percent as of 1993. If demand increases faster than anticipated and/or construction delays occur, reserve margins in some of these regions may be adversely affected.[4] If load growth falters below present estimates, however, construction plans may have to be changed, with potentially adverse effects on the financial status of affected utilities.

A 1984 analysis by the U.S. DOE[5] suggests that, since recent operating experience with large generating units (i.e., 500 MW or more) indicates that they tend to be less reliable and require more time for maintenance than small units, a 25 per-

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[3] ERCOT and MAPP may prove particularly sensitive, since they are also projected to fall below the 20 percent reserve criterion as well as the 5 percent adjusted reserve benchmark.

[4] For example, a recent study by J. Steven Herod and Jeffrey Skeer of the Office of Coal and Electricity Policy, U.S. Department of Energy projects regional reserve margins through 2000 under two different national demand growth scenarios. The first scenario assumes growth at 2.6 percent through 1990 and 2.4 percent from 1990 through 2000. The second, higher growth scenario assumes 3.3 percent growth through 1990 and 2.9 percent growth from 1990 to 2000. The utility capacity projections used in Herod and Skeer's analysis exclude: 1) coal units planned but not yet under construction as of the end of 1983, and 2) nuclear units only one-third complete as of that date. As would be expected, under these assumptions several regions show reserve margin problems earlier than indicated in figure 7-3. In particular, both ERCOT and MAPP would fall below 20 percent in the mid to late 1980s, highlighting these regions' dependence on planned additions. All regions would fall below 20 percent by 1994 under the high growth scenario. For further information, see J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs," presented at the 12th Energy Technology Conference and Exposition, March 1985. The views expressed in the report are those of the authors.

[5] U.S. Department of Energy (DOE), *Electric Power Supply and Demand for the Contiguous United States 1984-1993* (Washington, DC: DOE, June 1984.

Table 7-1.—Utility Type, By Region

Census region	NERC regions fully or partially included	Number of IOUs	Number of publicly owned utilities	Percent total electricity sales to ultimate customers from IOUs, by census region, 1983	Percent total electricity sales to ultimate customers from publicly owned utilities, by census region, 1983
New England	NPCC	24	43	91	9
Middle Atlantic	NPCC, MAAC, ECAR	23	49	92	8
East North Central	ECAR, MAIN, MAPP	40	165	90	10
West North Central	MAPP, SPP	34	217	64	36
South Atlantic	ECAR, MAAC, SERC	31	152	81	19
East South Central	ECAR, SERC	9	138	36	64
West South Central	ERCOT, SPP	24	113	81	19
Mountain	WSCC	27	52	70	30
Pacific	WSCC	14	55	62	39
Total, United States		226	984	76	24

NOTES: Totals may not equal 100 percent due to rounding.
IOU = Investor-owned utility.

SOURCE: Office of Technology Assessment, from Energy Information Administration, *Typical Electric Bills January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/EIA-0040(84); and Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, 1984).

cent margin may not completely assure system reliability in those systems which place heavy emphasis on large plants. Whether or not this will emerge as an issue remains unclear; as of 1980, ECAR, ERCOT, MAAC, and SERC were the only regions with more than 15 percent of total capacity in units equaling or exceeding 500 MW; of these regions, ERCOT had the highest percentage—25 percent.[6]

Opportunities for Consumer Side Alternatives to New Capacity

Conservation

Conservation can offer a cost effective alternative to a significant quantity of new capacity construction, and the National Association of Regulatory Utility Commissioners (NARUC) is actively encouraging utilities across the country to include conservation in their resource plans. From a utility's perspective, one of the major issues associated with relying on this "consumer side" supply strategy is that implementation depends on actions outside the utility's direct control. While different pricing strategies have been used to encourage conservation, customer responses are not entirely predictable. Utilities are also concerned about conservation efforts which might reduce off-peak demand without affecting the peak, thereby decreasing system load factor without decreasing the need for new capacity.

The energy conservation resource appears quite large, although estimates of the potential energy savings and capacity deferrals vary widely. OTA's assessment of conservation opportunities in specific energy-use categories can be found in several previous studies.[7]

Load Management

NARUC is also encouraging U.S. utilities to consider load management in their resource plans. Load shape patterns define the opportunities for load management. As figure 7-4 illustrates, these patterns differ among end-use sectors, with industrial loads generally more uniform than commercial or residential ones. Load shape variations between utility systems within NERC regions are as marked as the variations among regions. The load management opportunities within a given region are defined by many factors, including system reserve margins, expected load factors, customer profiles, the degree to which a utility generates its own power or purchases it from other systems, and public utility commission policies.

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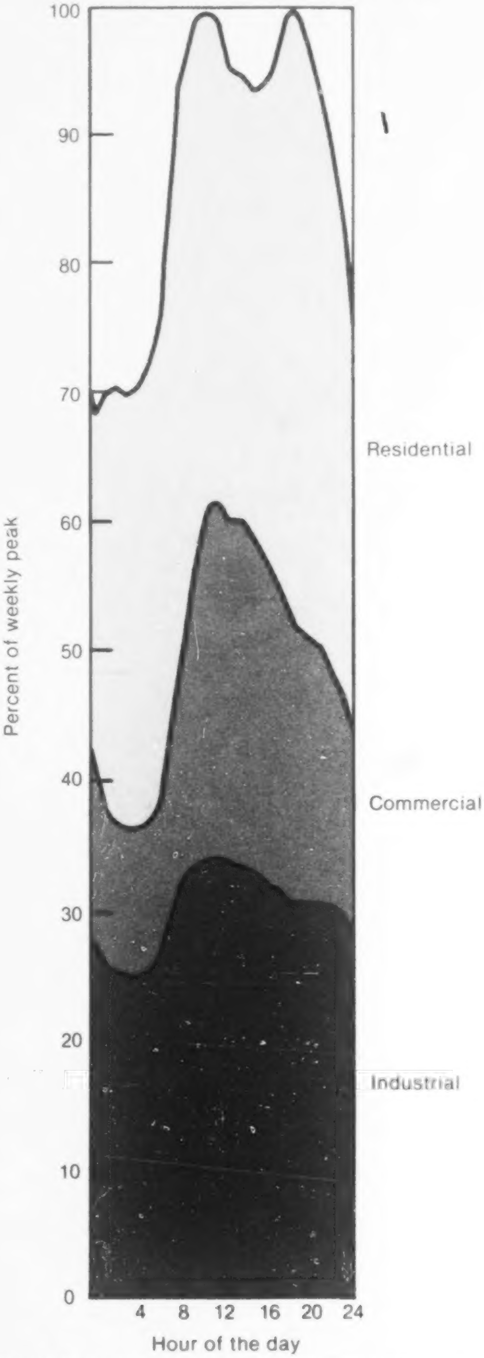
[6] Derived from generating plant database prepared for OTA in January 1985 by E.H. Pechan & Associates, Inc.

[7] U.S. Congress, Office of Technology Assessment (OTA), *Energy Efficiency of Buildings in Cities* (Washington, DC: U.S. Government Printing Office (GPO), March 1982); OTA, *Industrial Energy Use* (Washington, DC: GPO, June 1983); OTA, *U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability* (Washington, DC: GPO, September 1984.)

Figure 7-4.— Sample Load Curve for a Utility in the ECAR Region on a Day in January



SOURCE: Office of Technology Assessment, from James J. Mulvaney, "Assessment of R&D Benefits for the Electric Power Industry," Joint National Meeting, ORSA/TIMS, San Diego, CA, Oct. 26, 1982.

One of the key operational objectives behind load management is to increase system load factor—the ratio of average load to total load over a specified time interval. In the United States, regions with high load factors are generally characterized by moderate, stable climates and/or heavy industrial loads, while low load factors usually are indicative of high seasonal peaks in electricity use and/or little heavy industry.[8]

In all regions, there appear to be substantial opportunities for load management; these opportunities are discussed in detail in chapter 5. In particular, the residential market remains largely untapped, making areas characterized by high population density or high population growth attractive candidates (see table 5-1) if the obstacles discussed in chapter 5 can be overcome. Opportunities also remain in the commercial and industrial sectors.

In the long run, fuel reliance patterns may make load management an unattractive option in some regions if it defers replacement of costly oil- or gas-fired units.[9] This may be especially important in oil- or gas-dependent areas such as ERCOT, MAAC, NPCC, SPP, the Florida subregion in SERC, and two subregions of WSCC—the California-Southern Nevada Power Area and the Arizona New Mexico Power Area. From the consumer's standpoint, the deciding factor regarding the desirability of such deferrals will be the ultimate impact on electricity bills—a function of both electricity rates and electricity use. For utilities, the desirability of such deferrals will be heavily influenced by their cost relative to other electricity supply options.

Municipal utilities (munies) and rural cooperatives (coops), most of which buy the bulk of their power from other systems, are already actively pursuing load management to both improve load factor and minimize the cost of purchased power. These systems accounted for one-third of all the load control points in 1983. Munies and coops facing high demand charges on purchased power are expected to continue to provide a strong load management market through the 1990s in all regions. As suggested by the data presented in table 7-1, load management efforts may be particularly strong in the East South Central, Pacific, West North Central, and Mountain census regions—regions where publicly owned utilities serve significant portions of the electricity market.

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[8] NERC, *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

[9] James J. Mulvaney, Planning and Evaluation Division, Electric Power Research Institute, *Electric Generation System Development: An Overview*, November 1983.

Emphasis on load management and/or conservation has been particularly strong in several States, including Nevada, California, Florida, Wisconsin, New York, North Carolina, and the Pacific Northwest (Idaho, Montana, Oregon, and Washington).

Table 7-2.—Average Fuel Prices, By Region (in cents per million Btu)

Region and year	Coal	Residual oil[a] (#6)	Distillate oil[b] (#2)	Gas
ECAR:				
1983	168.1	451.9	625.6	426.9
1984	165.9	460.4	628.9	419.8
ERCOT:				
1983	164.3	503.7	517.9	362.3
1984	156.5	567.3	601.5	358.0
MAAC:				
1983	158.1	464.0	602.5	405.4
1984	166.3	488.0	614.6	434.1
MAIN:				
1983	186.7	605.6	621.4	506.4
1984	180.3	613.1	629.9	474.8
MAPP (U.S.):				
1983	128.8	419.5	596.9	365.9
1984	132.1	453.0	603.9	363.9
NPCC (U.S.):				
1983	194.8	446.8	635.4	395.9
1984	192.5	476.0	637.7	398.1
SERC:				
1983	191.8	427.3	621.0	261.3
1984	191.9	463.2	608.4	332.6
SPP:				
1983	166.3	373.8	615.3	251.3
1984	172.6	410.9	625.3	254.6
WSCC (U.S.):				
1983	109.4	602.5	619.0	500.5
1984	112.6	620.9	616.2	502.9

[a] Most of the oil burned by utilities (e.g., 90 percent) is residual oil; it is usually burned in base and intermediate load boilers.

[b] Distillate oil is burned in peaking units (i.e., combustion turbines and diesel engines).

SOURCE: Data generated for OTA by Energy Information Administration, Electric Power Division, U.S. Department of Energy, November 1984.

REGIONAL ECONOMIC AND REGULATORY CHARACTERISTICS AFFECTING TECHNOLOGY CHOICES

Rate Regulation Issues

Avoided Cost

Potential markets for many new generating technologies depend on the buy-back rates being offered by utilities under the avoided cost guidelines of the Public Utility Regulatory Policies Act (PURPA). Regional generalizations about these rates are complicated by the substantial variations within regions as well as the continued changes in rate offerings, primarily due to fluctuating projections of the costs of avoided fuel use.

Since fuel costs are a critical factor in the economics of technology alternatives, regional averages are presented in table 7-2. As this table illustrates, fuel costs are particularly high in NPCC and WSCC, two areas within which avoided cost rates are also high relative to the rest of the country. In general, the highest avoided energy rates (as of October 1984) were offered in NPCC, WSCC, ERCOT, and MAAC, with utilities in States in each of these regions offering rates equal to or above 6 cents/kWh. With the exception of Florida (SERC), States within these four regions were also the ones with utilities offering the highest capacity credits.[10]

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[10] From data presented in "'States' Cogeneration Rate-Setting Under PURPA, Part 4," *Energy User News*, vol. 9, Nos. 40-43, Oct. 1, 8, 15, and 22, 1984.

Table 7-3.—Average Residential, Commercial, and Industrial Electricity Prices, By Census Region

Census region	NERC regions totally or partially included by designated census regions	Residential rates[a] (¢ per kWh)		Commercial rates[b] (¢ per kWh)		Industrial rates[c] (¢ per kWh)	
		As of 1/1/83 bills	As of 1/1/84 bills	As of 1/1/83 bills	As of 1/1/84 bills	As of 1/1/83 bills	As of 1/1/84 bills
New England	NPCC	08.2	08.9	09.9	10.7	07.8	08.6
Middle Atlantic	NPCC, MAAC, ECAR	09.4	09.5	13.1	13.3	11.5	11.0
East North Central	ECAR, MAIN, MAPP	06.6	06.9	08.4	08.7	07.6	07.8
West North Central	MAPP, SPP	05.9	06.3	06.7	07.1	05.7	06.1
South Atlantic	ECAR, MAAC, SERC	06.5	06.9	07.3	07.5	06.8	07.1
East South Central	ECAR, SERC	05.5	0.56	06.3	06.3	06.1	06.1
West South Central	ERCOT, SPP	06.3	06.7	07.1	07.5	06.1	06.7
Mountain	WSCC	06.3	06.4	07.5	07.4	06.2	06.3
Pacific	WSCC	06.4	06.5	07.6	07.7	07.3	07.4

[a] Residential rates based on monthly usage of 750 kWh.

[b] Commercial rates based on monthly usage of 6,000 kWh (30 kW demand).

[c] Industrial rates based on monthly usage of 200,000 kWh (1,000 kW demand).

SOURCE: OTA, from Energy Information Administration (EIA), *Typical Electric Bills January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/EIA-004C84; Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, 1984); and 1984 data on commercial and industrial rates supplied by EIA's office of Coal and Power Statistics.

While avoided cost rates could fall in the near term (e.g., due to declining oil and gas prices) there is considerable disagreement on this issue.[11] As a policy decision to encourage cogeneration and new technologies, some State regulatory agencies (e.g., New York, New Jersey, and Iowa) are deliberately establishing or encouraging high buy-back rates.[12] These actions have often been the impetus for litigation; the Iowa rate was being challenged in court at the time this report went to press, while the New York rate had just avoided further challenge when, based on jurisdictional issues, the Supreme Court declined to review a lower court's decision upholding the rate.

Construction Work in-Progress

State policies towards construction work in-progress (CWIP) for new generating facilities are another factor which may strongly influence technology choices. Allowing CWIP in the ratebase helps avert the sudden rate shocks which can occur when major new plants come into operation; this assumes added importance in areas such as the New England and Mid-Atlantic States (see table 7-3) where electricity rates are already high relative to the rest of the country. Allowing CWIP in the ratebase can also make it easier for utilities to obtain financing for new construction projects, since this reduces the perceived and actual financial risks associated with new construction. Conceivably, such a policy could encourage all types of technology, but industry observers suggest it is most likely to favor conventional technologies—systems with which utilities are the most familiar and comfortable (see chapter 3 for a more detailed discussion).

Handling CWIP in retail rates is a State decision; rate policies are highly variable both between States and within the same States over time.[13] As of 1981, about 50 percent of all State regulatory agencies allowed some form of CWIP in the ratebase.[14] The Federal Energy Regulatory Commission (FERC), which controls wholesale rates, allows 50 percent of the funds used for construction to be treated as CWIP.

Licensing and Permitting of Small-Scale Systems

Because the economics of small or under-capitalized projects are particularly vulnerable to unanticipated costs or delays, regulatory policies affecting facility siting can also have a strong impact on technology deployment, especially when third-party producers are involved. To date, most of the experience in licensing and permitting small-scale alternative (especially renewable) technology projects has been in California. Although California's environmental review process is unique and perhaps the most rigorous in the country, some general trends appear to be emerging. Of these, the most important is that new, small-scale (i.e., less than 50 MW) technologies are *not* immune to controversy and opposition. While their impacts tend to be localized, concerns about them have in some cases led to lengthy and expensive environmental review, with the review costs borne by the developers. In other cases, the same types of projects have met no local resistance at all (see box 7B).

These experiences suggest that implementation of small-scale solar, geothermal, and wind technologies will be substantially influenced by local regulatory policies, the most influential being local zoning ordinances, land use permits, and public health standards. In areas where a land intensive project is proposed and sensitive habitat is affected, State and Federal laws may assume a dominant role, but these effects will be more site than region specific.

While siting of alternative technologies can be expected to be carefully monitored, especially in States with strongly protective environmental

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[11] OTA Workshop on Economic and Regulatory Issues Affecting New Generating Technologies, February 1985.

[12] Some industry observers also note that several utility commissions are beginning to react against high avoided cost rates and may move to set artificially low rates in an effort to protect their ratepayers. Other States such as California are stepping back from long-term levelized rates and returning to annual ones. Source: Allen Clapp, Director of Financial and Economic Analysis, North Carolina Alternative Energy Corp., personal communication, November 1984.

[13] For example, the Texas Public Utility Commission allowed CWIP in the rate base in 1980, but a subsequent 1984 ruling excluded it.

[14] Energy Information Administration, *Impacts of Financial Constraints on the Electric Utility Industry* (Washington, DC: December 1981), DOE/EIA-0311.

Table 7-4.—Selected Characteristics of Regional Electric Utility Generation Systems

Region	Demand growth (%)	Planned additions (%)[a]	Fuel reliance: Percentage of total generating capability												Years of projected failure to meet target reserve margins[b]		
			Coal				Nuclear				Oil and Gas						
			≥25%		≥45%		≥15%		≥25%		≥25%		≥50%				
	1984-93		1984	1993	1984	1993	1984	1993	1984	1993	1984	1993	1984	1993	25%	20%	5% (adj.)[c]
ECAR	2.4	14.4	•	•	•	•											'92-'93
ERCOT	4.0	40.1	•	•							•	•	•		'84-93	'88, '90-93	'91-93
MAAC	1.3	9.5	•	•			•	•		•	•	•	•				
MAIN	1.8	22.4	•	•	•	•	•	•		•					'83-84, '93		'86, '91-93
MAPP	2.4	11.5	•	•	•	•									'87-93	'90-93	'92-93
NPCC	1.7	14.0					•	•			•	•	•				
SERC	2.9	21.9	•	•	•	•	•	•									'93
SPP	2.7	21.3	•	•							•	•	•		'91-93		
WSCC	2.6	17.6		•							•						

[a] Expected increase over 1983 capacity

[b] Based on currently planned additions reported to NERC; power transfers not included.

[c] Adjusted to account for maintenance and other planned outages.

SOURCE: Office of Technology Assessment, prepared from data presented in U.S. Department of Energy, *Electric Power Supply and Demand for the Contiguous United States 1984-1993* (Washington, DC: U.S. Department of Energy, June 1984), DOE/IE-0003; and North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Princeton, NJ: NERC, 1984).

policies, the relatively less severe environmental impacts associated with many of the new technologies considered by this report may result in siting policies designed to encourage their development within specific guidelines.

Box 7B.—Lessons From the California Experience: Emerging Issues Affecting the Siting of Wind, Solar, and Geothermal Technologies

Siting constraints affecting the development of small-scale wind, geothermal, and solar electric facilities technologies in California have been highly variable. In general, esthetic impacts and potential disruption of sensitive wildlife habitats have been the primary issues affecting the siting of the land-intensive technologies (i.e., wind and solar electric). In some counties (e.g., Alameda), wind units have consistently been permitted within several months of application, at low cost and with little delay, but in others (e.g., Riverside), development has been held up for years due to litigation and county-imposed moratoriums on further development while the impacts of the facilities (especially visual impacts) were studied. In San Diego county, LaJet Energy Co.'s 4.5-MW solar thermal electric project has encountered substantial delays due to feared disruption of the habitat of a rare species of kangaroo rat; esthetic issues relating to the facility's visual impact have also been raised. Geothermal projects in high-temperature liquid dominated resource areas have encountered delays as well; to date, the primary issues here center around impacts on subsurface hydrology and sensitive aquatic systems.

The time, cost, and complexity associated with the facility permitting process appear to be a function of several important factors: the level of a developer's experience with, and knowledge of, applicable regulatory requirements; the level of a county planning staff's experience with the impacts of a particular technology; the adequacy of prescreening studies of a proposed development site to isolate important ecological characteristics and potential impacts; the adequacy of available "baseline" environmental data; the presence of rare, threatened, or endangered species; clashes between the impact of a project and local values or the local economic base; disputes over esthetic issues (in particular, disagreement regarding just *what* constitutes a negative impact); and disputes over the trade-off between economic benefits and potentially irreversible damage to natural resources. In many localities, the first facility to be permitted often experiences little delay; then, as regulators and residents become more aware of potential problems, the process becomes more complex and delays are more likely. These factors appear to be potentially applicable in other states as well; for example, development of a windfarm in the Shawangunk Mountains near Ellenville, New York, already has met substantial delay due to concerns about the facility's visual impacts.

KEY CHARACTERISTICS OF REGIONAL ELECTRICITY SUPPLY SYSTEMS

Present and Projected Fuel Reliance

Regional fuel and technology reliance establish the benchmarks for technology cost comparisons. While most systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, reliance on premium fuels is expected to be strong enough in some areas, i.e., ERCOT, MAAC, NPCC, and some subregions of SERC, SPP, and WSCC, that the economics of competing technologies will remain particularly sensitive to the price and availability of oil and gas (see figures 7-5 and 7-6, and table 7-2).[15] As discussed in the section on demand uncertainty, this sensitivity will be heightened if there are significant changes in actual demand

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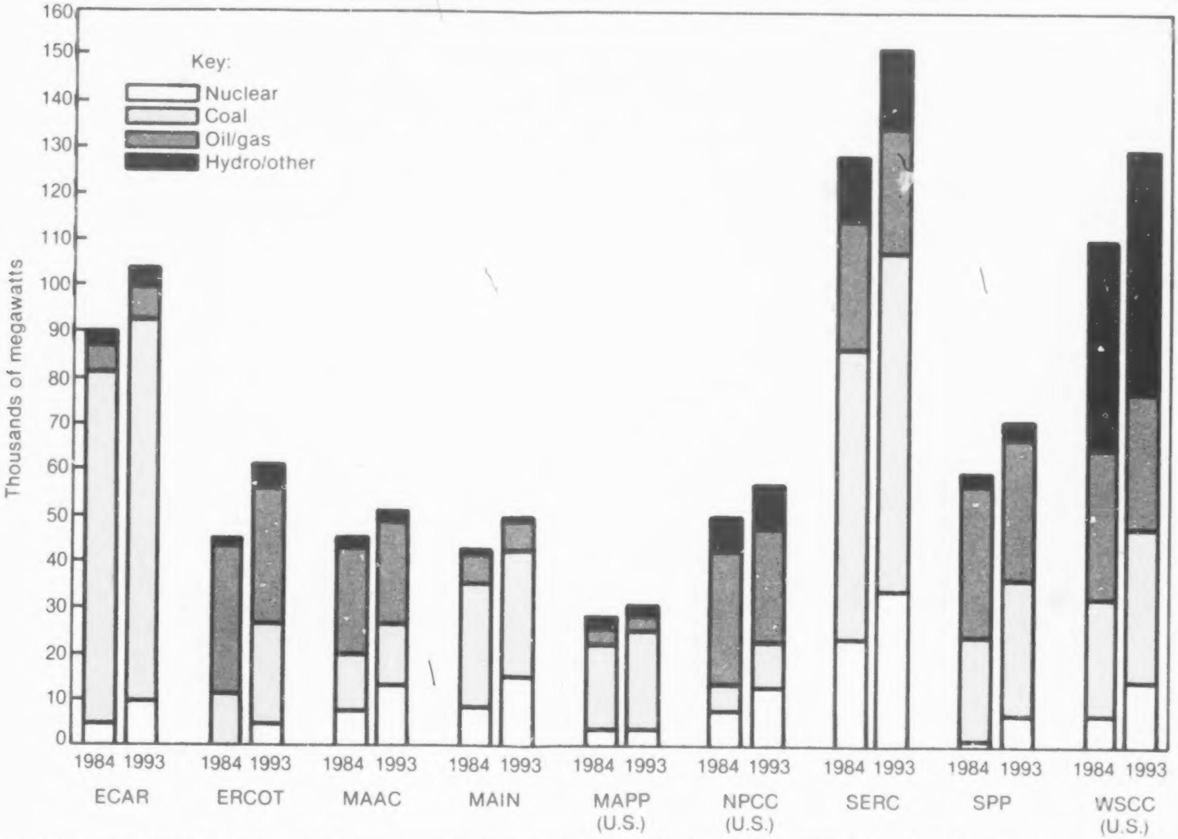
[15] These fuel reliance projections are from NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984; and from NERC, *14th Annual Review*, op. cit., 1984

The reader should note that all of the 1984 figures cited from these two NERC documents are *projections* made by the reliability councils in early 1984 (i.e., January-April).

Figure 7-5.—Regional Utility Capacity by Fuel Use, 1984 and 1993



SOURCE: Office of Technology Assessment, from data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Trenton, NJ: NERC, 1984).

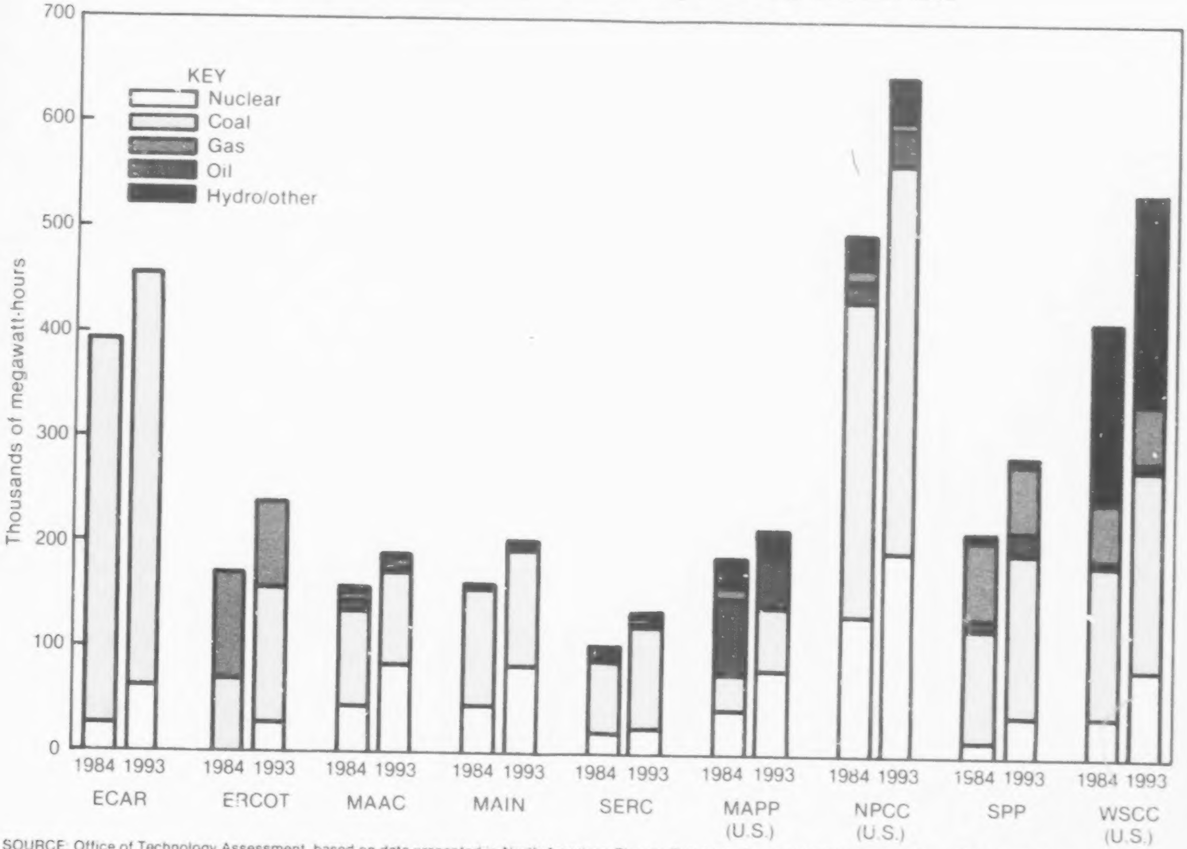
growth requiring either cancellation of plants under construction or rapid construction of new capacity. These issues are more fully described in the regional profiles.

Opportunities for Plant Betterment and Life Extension

If scheduled retirement of aging powerplants can be delayed by plant rehabilitation or efficiency improvements, the need for new construction may be deferred. As table 7-5 illustrates, deferral prospects vary considerably by region. At least 40 percent of the fossil-fired steam plants in the MAIN, NPCC, and WSCC regions will be over 30 years old by 1995, making life extension a potentially attractive option. In terms of total capacity, the opportunities for life extension appear highest in ECAR, SERC, SPP, and WSCC.

Having a large number of older plants does not mean life extension or plant betterment will be the most cost-effective supply enhancement option; as discussed in chapter 5, choosing this option will depend on site-specific economics. Nonetheless, the resource scope alone promises to make it an important factor affecting regional adoption of new technologies; in all but one region, the life extension base exceeds regional capacity additions planned for the decade of 1983-93.

Figure 7-6.—Regional Utility Generation by Fuel Use, 1984 and 1993



SOURCE: Office of Technology Assessment, based on data presented in North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993* (Trenton, NJ: NERC, 1984).

Table 7-5.—Life Extension Resource Base: Age of Fossil-Fired Steam Plants, By Region

Region	Percent FF capacity ≥30 years old as of 1995	Total installed FF capacity ≥30 years old as of 1995 (MW)	Total utility plant capacity additions planned for 1993 over 1983 installed levels (MW)
ECAR	32.9	33,335	12,083
ERCOT	20.4	12,186	17,546
MAAC	35.5	11,589	4,435
MAIN	41.3	14,172	9,157
MAPP (U.S.)	25.8	6,695	3,203
NPCC (U.S.)	52.6	16,806	7,082
SERC	35.8	32,239	27,348
SPP	30.0	21,359	12,646
WSCC (U.S.)	39.5	24.811	19,630

KEY: fossil-fired steam plants.

SOURCE: Office of Technology Assessment, from data generated by E. H. Pechan & Associates, December 1984; and North American Electric Reliability Council (NERC), *Electric Power Supply and Demand, 1984-1993*, (Trenton, NJ: NERC, 1984).

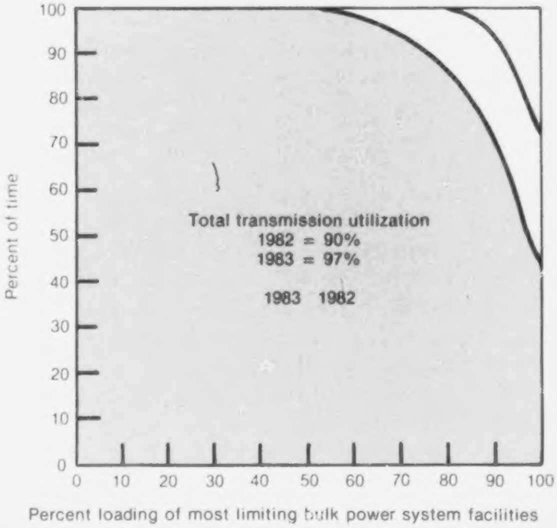
Supply Enhancements From Interregional and Intraregional Power Transfers

The amount and importance of interregional and intraregional power transfers has increased dramatically over the past four decades. While such transfers historically have been used to increase overall system reliability (i.e., emergency transfers to support energy-deficient areas during emergencies), the more recent emphasis has been on economy transfers which displace high cost, fossil fuel generation with cheaper electricity from neighboring systems. This trend has led many transmission systems to be consistently operated at or near maximum secure loading levels. In systems throughout the country, high loading levels are now raising concern about impacts on overall system reliability. Related physical transmission limits are curtailing economically attractive exchanges into many oil- and gas-dependent regions.[16]

The situation in MAAC, where considerable amounts of energy are imported from ECAR and SERC, highlights these growing problems. In 1982, MAAC's most limiting bulk power facilities were loaded to full capacity 40 percent of the time; 1 year later, this climbed to 70 percent. In that same year (1983), the system was used at 90 percent of rated capacity almost 95 percent of the time[17] (see figure 7-7). When systems are used at this intensity, their ability to respond to unexpected, severe disturbances is reduced, thereby increasing the risk of service interruption.

Rather than increasing reliability through redundancy, i.e., building new power lines, utilities are responding by developing more sophisticated protective relaying schemes and operating procedures. Some engineers argue that the net result of this new trend may be increased load shedding, indicating acceptance of increased risk of customer service interruptions (perhaps at preselected sites) when it results in net economic gain.[18] A combination of factors probably underlies this new trend, including anticipation of continued escalation of construction costs, interest rates, and fuel costs, as well as public opposition to (and the regulatory complexity of) building new plants or new transmission lines.[19]

Figure 7-7.—Historical Transmission Loading Patterns in MAAC



SOURCE North American Electric Reliability Council (NERC), *14th Annual Review of Overall Reliability and Adequacy of Bulk Power Supply in the Electric Utility Systems of North America, 1984* (Princeton, NJ: NERC, 1984), p. 18.

Figure 7-8 summarizes power transfer capabilities among regions; table 7-6 shows expected net import/export levels by region through 1993 (these are relatively long-term "firm capacity" exchanges set by contract; economy transfers are far more variable and predictions regarding their regional levels are not included). In general, if demand growth follows present predictions and current construction plans are implemented, utilities with large amounts of coal-fired generation probably will continue to be net exporters of power, while systems trying to reduce use of expensive-to-operate oil and gas units will be net purchasers of cheaper power—*if* they have access to it. However, it is unlikely that power transfers will be a substantial source of alternative capacity in many NERC regions due to the heavy use of existing transmission capacity, the limited

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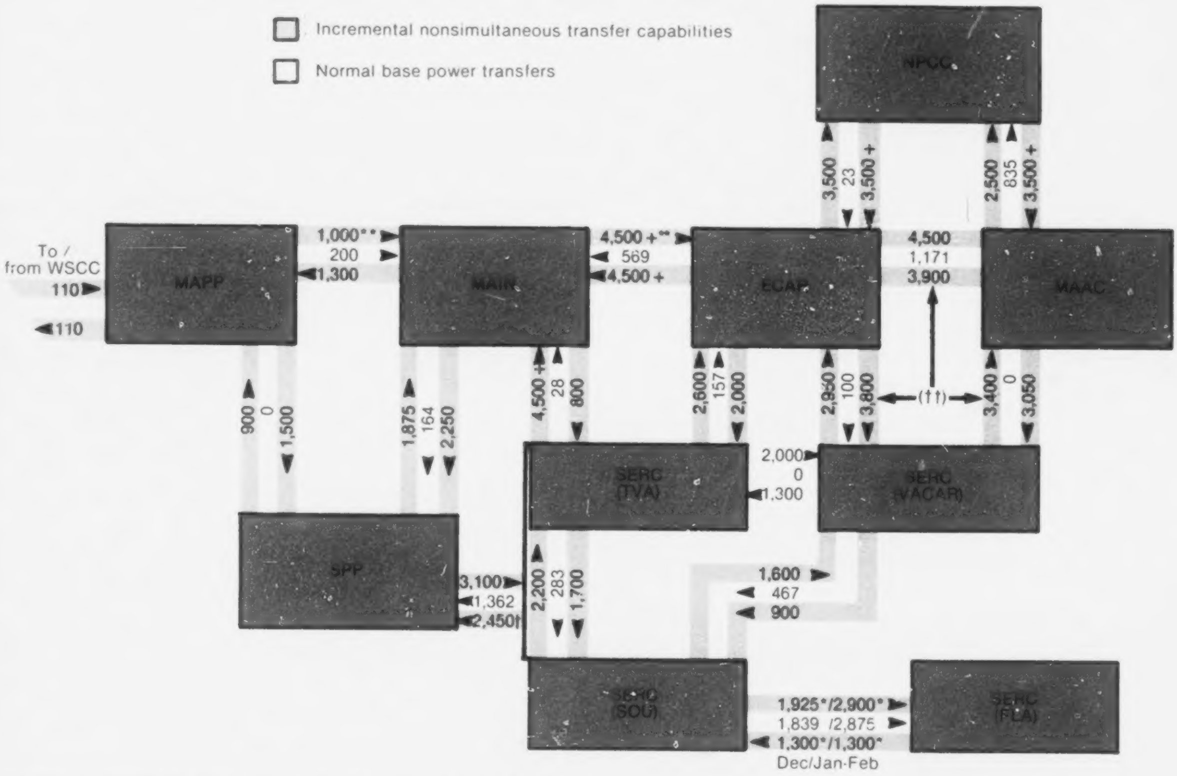
[16] NERC, *14th Annual Review*, op. cit., 1984; and Energy Information Administration, *Interutility Bulk Power Transactions* (Washington, DC: U.S. Department of Energy, October 1983), DOE/EIA-0418.

[17] NERC, *14th Annual Review*, op. cit., 1984.

[18] Ibid.

[19] EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

Figure 7-8.—Interregional and Intraregional Power Transfer Capabilities


Incremental nonsimultaneous transfer capabilities
Normal base power transfers
NPCC
MAPP
MAIN
ECAR
MAAC
SERC (TVA)
SERC (VACAR)
SPP
SERC (SOU)
SERC (FLA)
To / from WSCC
110
110
1,000**
200
1,300
4,500+**
569
4,500+
4,500
1,171
3,900
3,500
23
3,500+
2,500
835
3,500+
900
0
1,500
1,875
164
2,250
4,500+
28
800
2,600
157
2,000
2,950
100
3,800
(††)
3,400
0
3,050
2,000
0
1,300
3,100
1,362
2,450†
2,200
283
1,700
1,600
467
900
1,925*/2,900*
1,839 /2,875
1,300*/1,300*
Dec/Jan-Feb

(†) With no additional import into the South Louisiana Area of SPP.

(††) The transfer capabilities between ECAR, MAAC and VACAR are preliminary values taken from ongoing studies. These capabilities are based on thermal limits only. Voltage limitations may cause certain of these capabilities to be lowered.

* Total amount of power that can be transferred in a reliable manner.

** With a specific operating procedure in effect.

(+) No significant transmission limit at this level.

SOURCE: North American Electric Reliability Council (NERC), *1984/85 Winter Assessment of Overall Reliability of Bulk Power Supply in the Electric Utility Systems of North America* (Princeton, NJ: NERC, Nov. 15, 1984), p. 16.

number of new lines scheduled for operation within the next decade, and the long lead times associated with siting additional lines. The few exceptions are discussed in the regional profiles.

Prospects for Nonutility Generation

Cogeneration

A 1983 OTA assessment estimated the technical cogeneration potential in the United States by the year 2000 at 200,000 MW in the industrial sector and 3,000 to 5,000 MW in the commercial, agricultural, and residential sectors. Actual implementation is expected to be considerably less, depending on a broad range of economic and institutional considerations.[20] For example, if a 7 percent rate of return after inflation is used as the cut-off point for acceptable project economics a 1984 study prepared for

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[20] U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-192.

Table 7-6.—Actual and Expected Power Transfers, 1983-93[a]

Region	Years expected to be net exporter	Net exports (range in MW)		Years expected to be net importer	Net imports (range in MW)	
		Low	High		Low	High
ECAR	1984-92	270 summer 1992	3,938 summer 1994	1993	175 winter 1993	178 summer 1993
ERCOT	0	0		1984-93	582 winter 1986 summer 1987	709 winter 1989
MAAC	0	0		1984-93	107 winter/ summer 1993	1,582 winter/ summer 1984
MAIN	1985-93	65 summer 1993	536 winter 1989	1984	42 winter 1984	462 summer 1984
MAPP (U.S.)	1984-92 winters	354 winter 1984	658 winter 1986	1984-93 summers	327 summer 1987	556 summer 1993
NPCC (U.S.)	Winters of 1991, 1992, 1993	81 winter 1991	101 winter 1993	1984-93	77 winter 1990	1,747 summer 1985
SERC	1984-89 winter summer	300 summer 1985	1,540, winter 1984	summer 1984; 1989-93	200 winter 1989- winter 1991	1,300 winter 1992
SPP	1992-93	240 summer 1993	539 winter 1993	1984-92	226 winter 1984	1,017 summer 1987
WSCC (U.S.)	0	0		1984-93	183 winter 1984	610 winter 1983

[a] Firm power transfers only; economy purchases are not included.

SOURCE: Office of Technology Assessment, from U.S. Department of Energy (DOE), *Electric Power Supply and Demand for the Contiguous United States, 1983-1993* (Washington, DC: DOE, June 1984), DOE/IE-003.

DOE[21] estimates that 39,348 MW of industrial cogeneration capacity are presently available. Fifty-four percent of this total is in six States. Three of them—Texas, California, and Louisiana (corresponding to ERCOT, the California-Southern Nevada subregion of WSCC, and the southern portion of SPP) account for 31 percent of the total potential, making these areas especially important in terms of possible contributions from nonutility generators. Pennsylvania, Ohio, and New York (corresponding to parts of ECAR, MAAC, and NPCC) account for an additional 16 percent, making contributions in these States also substantial relative to the country as a whole. The potential is not expected to be high in the New England, Northwest, North Central, and Central DOE regions, although individual States within these regions, e.g., New York, may be exceptions. Table 7-7 presents a summary of the regional cogeneration opportunities identified by the study and lists the States included in each region. These estimates are based on 1980 data; the study projects that 47,435 MW in addition to the 39,348 MW presently available will be available by the year 2000.[22]

While some utilities consider the anticipated impact of power from nonutility generators in their demand forecasts, capacity plans, and other data submitted to NERC for preparation of its annual reports, many others do not. This results in inconsistent treatment and probable underrepresentation of these potential resources by the NERC projections cited in this chapter.

Resource Availability

Regional differences in resource availability will define the range of opportunity for many new technologies considered in this assessment.

As figure 7-9 illustrates, geothermal development is expected to be confined to the Southwest and Hawaii.

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[21] Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, *Industrial Cogeneration Potential (1980-2000) for Application of Four Commercially Available Prime Movers at the Plant Site, Final Report*, 1984.

[22] Ibid.

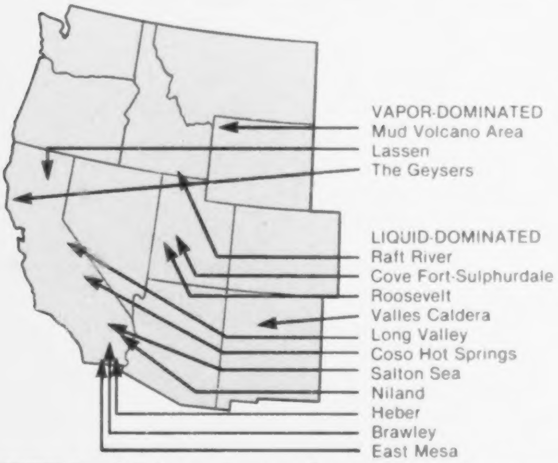
Table 7-7.—Estimated Maximum Industrial Cogeneration Potential Available as of 1980

EIA/DOE region	States included	NERC regions fully or partially included	Percent of potent plants	Percent of total plants nationally	Potential MW	Percent of potential MW nationally
New England	ME, VT, NH, MA, CT, RI	NPCC	189	5	1,690	4
NY/NJ	NY, NJ	NPCC, MAAC	540	15	3,544	10
MidAtlantic	PA, DE, MD, VA, WV	MAAC, ECAR, SERC	470	13	4,155	11
South Atlantic	KY, TN, NC, SC, GA, AL, MS, FL	SERC, SPP, ECAR	679	19	6,368	16
Midwest	WI, MI, IL, IN, OH	MAIN, ECAR	850	23	6,255	16
Southwest	TX, OK, NM, LA, AR	ERCOT, SPP, WSCC	348	10	9,442	24
Central	IA, NE, MO, KS	MAPP, MAIN, SPP	121	3	1,553	4
North Central	ND, SD, MT, WY, UT, CO	WSCC, MAPP	28	1	736	2
West	CA, NV, AZ, HI	WSCC	359	10	4,241	11
Northwest	WA, OR, ID, AK	WSCC	60	2	1,360	4
		Total	3,644	[a]	39,344	[a]

[a] Totals exceed 100 percent due to rounding.

SOURCE: Office of Technology Assessment, from: 1) Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, *Industrial Cogeneration Potential (1980-2000) for Application of Four Commercial Available Prime Movers at the Plant Site, Final Report*, vol. I, prepared for U.S. Department of Energy, Office of Industrial Programs (Springfield, VA: National Technical Information Service, August 1984), DOE/CS40403-1, and 2) information provided to OTA by the U.S. Department of Energy, April 1985.

Figure 7-9.—Major U.S. Hydrothermal Resources



SOURCE: Peter D. Blair, et al., *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Unley & Sons, 1982), p. 9. Reproduced from R. L. Smith and H. R. Shaw, U.S. Geological Survey Circular 76, 1975.

While the wind resource is strong in the West (WSCC) and most of the development to date has occurred there, the resource is promising in many other areas, including parts of ERCOT, MAPP, NPCC, and SPP (figure 7-10).

"Incompatible" land uses may limit the land-intensive wind and solar technologies, especially in areas where a high premium is placed on visual esthetics (see the earlier discussion on licensing and permitting). In densely populated regions such as NPCC, development of these technologies may be more affected by land availability rather than by resource availability. For example, solar electric development will be particularly constrained in heavily populated areas where insolation levels require high acreage per kilowatt of power production. Figure 7-11 illustrates the national solar resource.[23]

While land availability constraints may limit solar and wind development, these same constraints are expected to augment the attractiveness of fuel cells and batteries in urban areas. Resources for CAES development are available in all regions, as illustrated in figure 7-12.

Regions projecting continued and/or expanded emphasis on coal generation (especially ECAR, MAIN, MAPP, and SERC) will be likely candidates for AFBC and IGCC development (see table 7-4).

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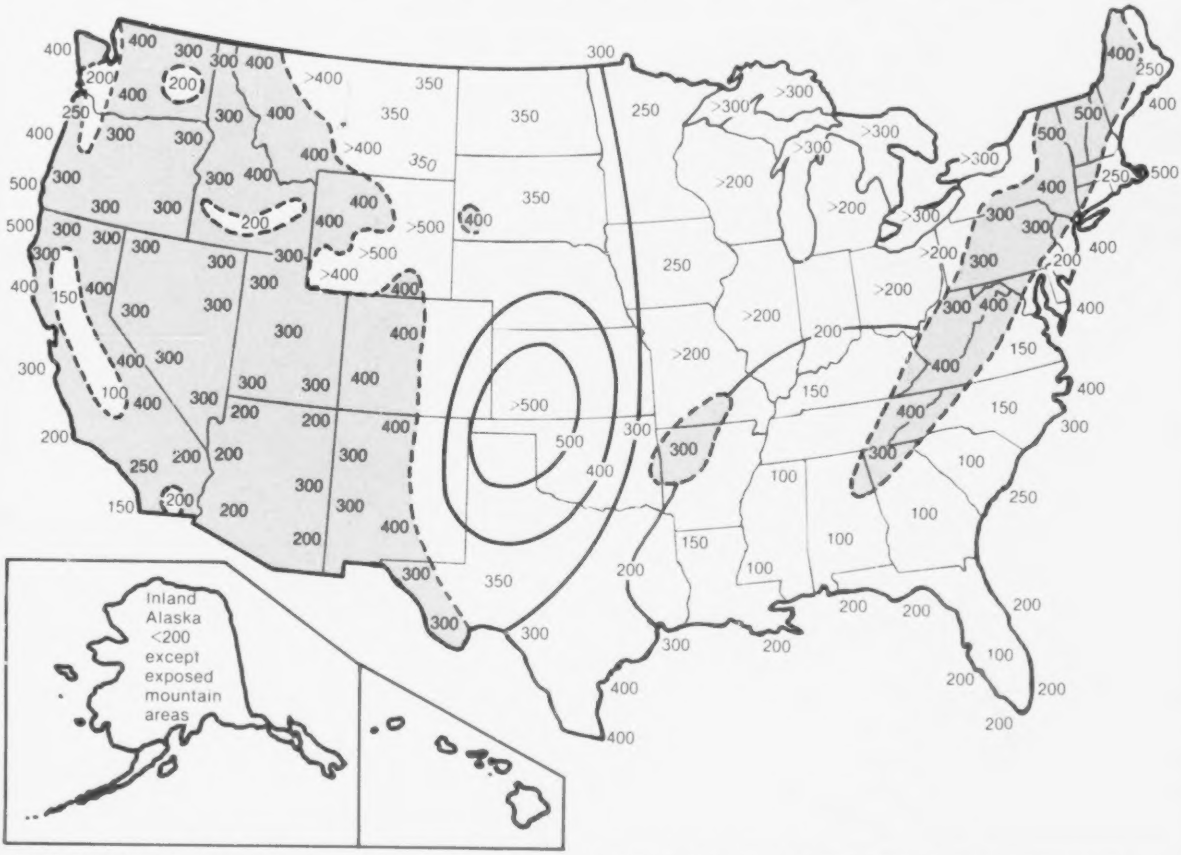
[23] Solar availability in the United States varies by close to a factor of 2 between the Southwest, on the one hand, and the Northwest and Northeast on the other.

Figure 7-10.—Average Annual Wind Power (watts per square meter)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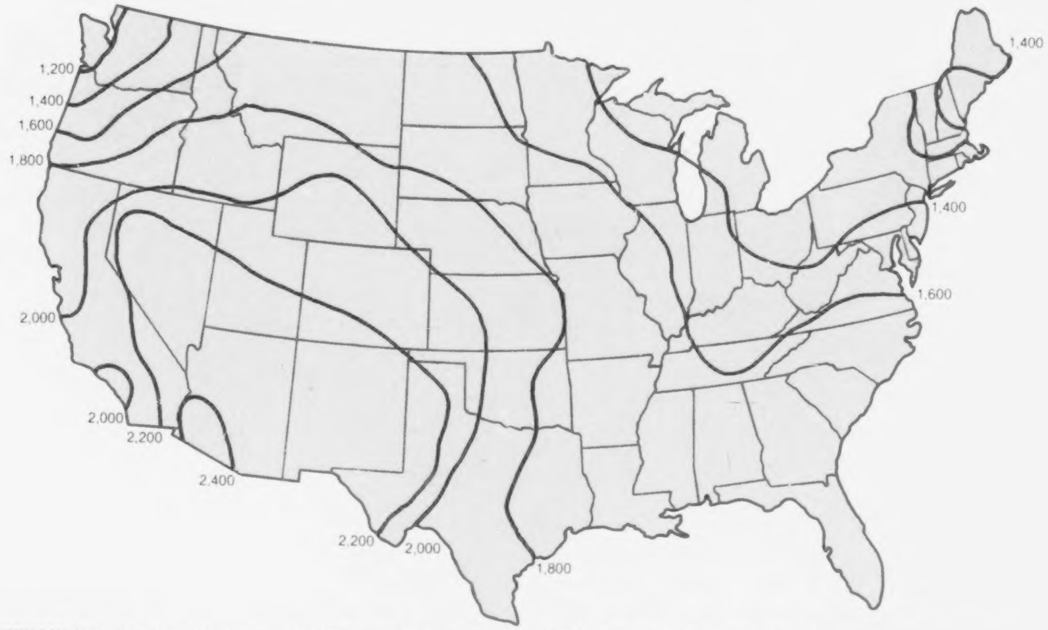
Inland
Alaska
<200
except
exposed
mountain
areas

NOTES: Estimates are for wind speeds at a point 50 meters above land surface. For mountainous areas (shaded), the figures provided are low estimates of wind speeds on exposed ridges or summits.

SOURCE: From Kendal and Nadis' *Energy Strategies: Toward a Solar Future*. Copyright 1980, Union of Concerned Scientists. Reprinted with permission from Ballinger Publishing Co.

Figure 7-11.—Average Annual Solar Radiation (kWh/m^2 – yr)


1,200
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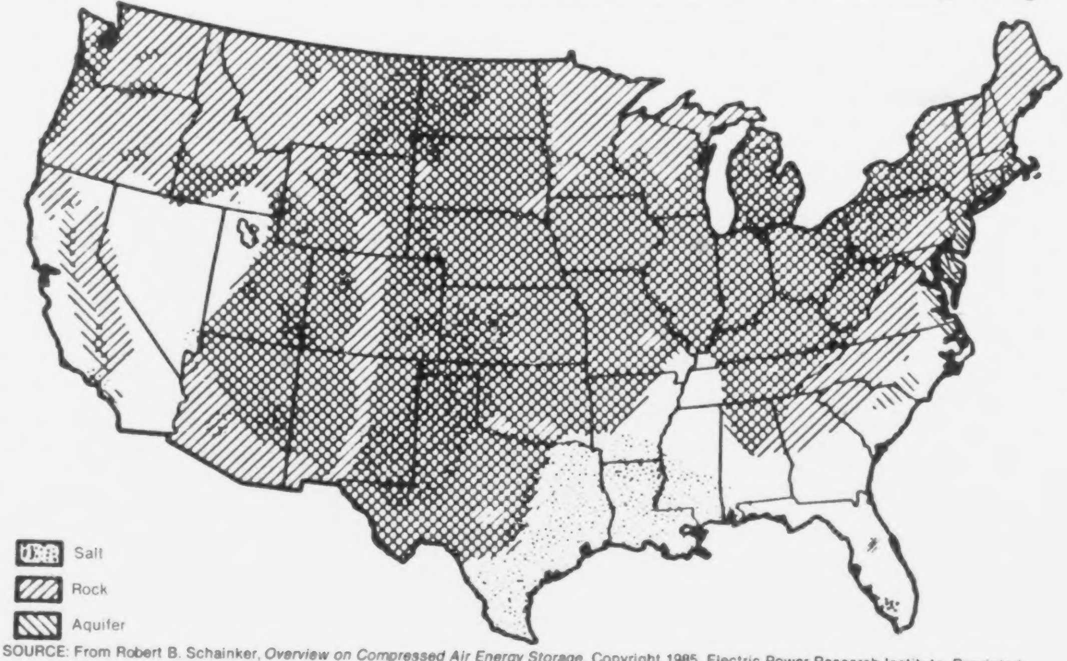
2,200
2,400
2,200
2,000
1,800
1,400
1,400
1,600

SOURCE: M. G. Thomas and G. J. Jones, "Grid-Connected PV Systems: How and Where They Fit," *Sandia Report: A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference*, prepared for the U.S. DOE, Edward L. Burgess (ed.) (Albuquerque, NM: Sandia National Laboratories, May 1984).

Figure 7-12.—Geological Formations Potentially Appropriate for Compressed Air Energy Storage


Salt
Rock
Aquifer

SOURCE: From Robert B. Schainker, *Overview on Compressed Air Energy Storage*, Copyright 1985, Electric Power Research Institute. Reprinted with permission of the publisher.

REGIONAL FUEL AND TECHNOLOGY RELIANCE[24] PROFILES

East Central Area Reliability Coordination Agreement (ECAR)

ECAR
MICHIGAN
PENNSYLVANIA
INDIANA
OHIO
MD
WEST VIRGINIA
KENTUCKY
VIRGINIA

In anticipation of a 2.4 percent regional annual growth rate in summer peak demand, ECAR is projecting a 14 percent increase in its 1983 installed capacity levels by 1993.[25] The region relies heavily on coal (93 percent of 1984 electricity generation) and is expected to continue this reliance well into the 1990s. Present construction plans also project a substantial increase in dependence on nuclear energy, from 7 percent of total generation in 1984 to 13 percent in 1993.[26] There is a possibility that several of these nuclear plants will not be completed on schedule; member systems have already had to cancel four nuclear units[27] (3,600 MW) which were well along in construction. Two of these (Midland 2 and Zimmer 1) are among the costliest plants in the country.[28]

Assuming completion of presently planned units (i.e., as of the 1984 14th Annual NERC report), ECAR's 1993 reserve margin is currently estimated at 32 percent[29]—well above traditional measures of adequacy. According to the region's 1984 annual report, of the units planned and/or currently under construction, five nuclear units (5,100 MW) scheduled for completion by 1988, nine combustion turbines (735 MW) and three coal plants (1,550 MW) scheduled for completion between 1989 and 1993 may not be finished on schedule, raising some questions about adequate reserves at the end of the decade if demand grows as expected. If these plants are completed on time, 1993 projections for adjusted reserves (4.6 percent) fall slightly below suggested reliability criteria[30] (see table 7-4), while reserve margin estimates remain well above 20 percent. As figure 7-3 suggests, the national high demand growth scenario could lead to reserve shortfalls in the region, while lower demand scenarios leave ECAR with a sizable capacity surplus.

ECAR's heavy dependence on coal makes it particularly vulnerable to the cost of more stringent acid rain regulations. Plant derating, retirement of older units which cannot be economically retrofitted, and increased down-time from maintaining additional flue gas desulfurization equipment could create a need for additional capacity, depending on the emissions reductions required, the age-mix of the plants affected, projected electricity demand in the area, and related factors. Concerns regarding these regulations are expressed in the annual NERC reports for all the coal-dependent regions.[31]

ECAR is characterized by moderate levels of both intraregional and interregional transfers, including power imports from Canada. Within the region, these transfers are due to load diversity; inter-regional sales are economy transfers displacing costlier fuel, especially in the MAAC region. The region is expected to be a net exporter through the early 1990s.[32] ECAR's current transmission system is being used close to its limit; 1,800 miles of new line are under construction to strengthen the region's overall transfer ability.[33]

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[24] All of the NERC regional maps included in this section are reprinted with permission from NERC, *14th Annual Review*, op. cit., 1984.

[25] Historically, ECAR has been winter peaking, but the region is expected to be summer peaking from 1984 on.

[26] NERC, *14th Annual Review*, op. cit., 1984.

[27] Marble Hill 1 and 2, Midland 1, and Zimmer 1.

[28] According to *Forbes* (James Cook, "Nuclear Follies," *Forbes*, vol. 135, No. 3, Feb. 11, 1985, pp. 82-100), the cost per installed kilowatt at Midland 2 was $4,889, and the cost per kilowatt at Zimmer 1 was at $3,827, compared with an $1,180 cost per kilowatt at Duke Power's McGuire 2 plant.

[29] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

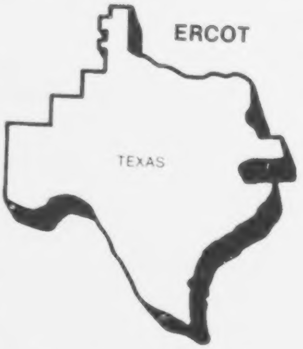
[30] Ibid.

[31] NERC, *14th Annual Review*, op. cit., 1984.

[32] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[33] NERC, *14th Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

Electric Reliability Council of Texas (ERCOT)



Demand is expected to grow at an average annual rate of 4 percent in ERCOT over the next decade—the highest growth rate of all the NERC regions. Member utilities depend heavily on gas (60 percent of total electricity generation in 1984; projected to decrease to 35 percent in 1993); they are planning to decrease this dependence by building several thousand megawatts of new coal/lignite and nuclear capacity.[34]

Present utility capacity plans call for a 40 percent increase in installed capacity over 1983 levels by 1993 (see table 7-4). Even with this construction, ERCOT may approach or fall below several suggested reliability criteria within the next decade if present demand predictions prove to be accurate. For example, the adjusted reserve margin is projected to fall to 4.3 percent as of 1991, and the installed reserve margin is expected to fall below 19 percent from 1990 through 1993.[35] Figure 7-3 suggests the region may experience large capacity shortfalls relative to other regions under all but the lowest national growth scenarios.

Power from cogenerators could offset possible shortfalls in the region, since potential contributions from cogeneration may be inadequately reflected by current utility resource plans. While the present industrial cogeneration potential in ERCOT is estimated at 5,110 MW,[36] the cogeneration capacity additions shown in the region's 1984 report total 885 MW for the 1984-93 planning period; total capacity contributions from "other" sources for 1993 is estimated at 4,862 MW—this figure includes conservation, load management, energy from refuse, and other undesignated sources as well as cogeneration.[37] In response to the large cogeneration resource in-state, the Texas utilities commission recently ordered one Texas utility to show cause why several planned lignite-fired plants should not be decertified in light of potential capacity from cogenerators.[38]

Whether or not the full cogeneration potential in ERCOT is realized will depend to a large extent on relative economics; it is likely that cogeneration will be one of the major supply options with which new power generating technologies will have to compete.

Imports from other regions are expected to play an increasing role in ERCOT. Historically, there have been large amounts of interchanges among ERCOT member systems, mainly for emergency purposes, but ERCOT has been relatively isolated from other regions. Lines are presently under construction to link ERCOT systems with SPP and better integrate remote generating sources within ERCOT.[39] The region is expected to be a net importer for the next decade (see table 7-6).

Mid-Atlantic Area Council (MAAC)

PENNSYLVANIA
NEW JERSEY
DEL
MD
MD
MAAC

MAAC utilities rely predominately on nuclear and coal-fired generation. By 1993, nuclear's share of total generation is expected to jump from 28 to 45 percent, while coal's share of generation will drop about 10 percentage points.[40] According to a recent NERC report, the "comparatively weak financial position of some electric utilities in the Region may force decisions to reduce capital expenditures, which will delay the service dates of generating units under construction."[41] Two units (one nuclear, one oil-fired) have already been delayed (the nuclear unit by 2 years, from October 1988 to April 1990; the oil unit from June 1992 to beyond the 1984-93 planning period). MAAC planners cite reduced demand forecasts and financing problems as the major reasons for the delays.

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[34] NERC, *14th Annual Review*, op. cit., 1984.

[35] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[36] Dun & Bradstreet and TRW, *Industrial Cogeneration Potential (1980-2000)*, op. cit., 1984.

[37] NERC, *14th Annual Report*, op. cit., 1984; and NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[38] At a recent conference on utility applications for renewable technologies, the vice president of Houston Light and Power noted this fact and also remarked that "We have had 1300 MWe (of cogenerated power) thrust on us over two years." In addition, in 1984 when the company sought to add 300 MW from third-party producers to boost its reserve margin to 20 percent, cogenerators offered 1,275 MW. (Sources: REI/EEI Conference, op. cit., November 1984; and "Developers, Utilities, Lay Out Their Arguments," *Solar Energy Intelligence Report*, Nov. 19, 1984, p. 365).

[39] NERC, *14th Annual Review* , op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[40] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

Presently, annual demand growth is predicted to remain at 1.3 percent and reserve margins are expected to be adequate through the early 1990s. As figure 7-3 illustrates, given present construction plans, reserves would fall below 20 percent only under the 4.5 percent national growth scenario. Of course, further plant delays (or unexpected changes in demand growth) could change this situation. The region is already taking maximum possible advantage of economy power transfers from neighboring regions, notably ECAR and SERC; transmission limitations are expected to keep these levels below the amount MAAC utility systems would prefer. These factors may create an attractive climate for short lead time, new technologies if those technologies are economically competitive at the time a need for additional power is recognized.

While only 7 percent of the electricity generated in 1984 in MAAC was expected to be oil-fired (decreasing to 4 percent by 1993), oil and gas comprise nearly 52 percent of MAAC's 1984 installed capacity and will probably account for 44 percent in 1993.[42] Oil is the region's "swing" fuel: if circumstances delay construction or in some way impede use of the region's coal and nuclear capacity, or if demand increases substantially faster than expected, oil use will increase. In that case, oil costs will strongly influence the relative economics of alternative generating options.

Like other coal-using regions, MAAC is vulnerable to changes in present environmental regulations. Regional planners note that, if present regulations are substantially tightened, the impact on some of the area's older coal plants could affect overall system reliability, because some units might have to be retired and the output of others would be substantially reduced. This could create a need for additional power sources—another potential opportunity for new technologies.

Nuclear power is another important issue in the region. In particular, developing sufficient away-from-reactor storage facilities for radioactive wastes is a concern for some MAAC utilities which face shortages in onsite storage facilities at some of their older nuclear plants.[43] In the long run, this too may affect technology choices in the region.

Mid-America Interpool Network (MAIN)

MICHIGAN
WISCONSIN
ILLINOIS
MISSOURI

MAIN expects its installed capability to exceed 1983 levels by 22 percent in 1993; this construction level is based on a predicted demand growth rate of only 1.8 percent. The region presently relies heavily on coal (68 percent of total electricity generation in 1984) and nuclear power (29 percent). By 1993, coal is expected to decrease to 56 percent of total electricity generated by electric utilities in the region, while nuclear's share is expected to increase to 41 percent.[44]

Given their emphasis on coal generation, the region's utility systems are sensitive to changes in air emissions regulations. Potential construction delays could also be a problem—85 percent of all of the plants presently under construction in MAIN are nuclear; seven new units are planned to come into commercial service between 1984 and 1987.[45] Delays would be especially important in light of projected reliability criteria for the region; as table 7-4 illustrates, given construction plans as of 1984, the area is expected to fall below the 5 percent adjusted reserve margin criterion in the early 1990s. Figure 7-3 suggests further vulnerability under high national demand growth scenarios (i.e., 3.5 and 4.5 percent). Given present oil- and gas-fired capacity levels (15 percent of 1984 capacity; 2 percent of 1984 generation), oil and gas could be "swing" fuels in the region.

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[41] NERC, *14th Annual Review*, op. cit., 1984, p. 31.

[42] NERC, *14th Annual Review*, op. cit., 1984.

[43] Ibid.

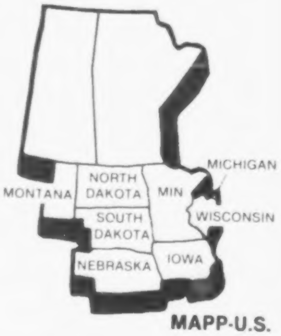
[44] Ibid.

[45] Ibid.

MAIN expects to be a net power exporter over the next decade; it is one of the only regions projecting commitment to "surplus" capacity so it can take advantage of economy power sales to neighboring regions.[46] A surplus is also seen as desirable because it would ease routine maintenance schedules by removing some of the pressure to get a unit being serviced back on line immediately.[47] It should be noted, however, that MAIN's expected seasonal net export levels (for firm capacity, not economy transfers) range from 65 to 536 MW; both ECAR and SERC expect to export considerably higher levels (see table 7-6).[48]

Given the high percentage of nuclear plants presently under construction and considering the historical tendency for these types of plants to be more prone to delay than coal-fired units,[49] some MAIN utilities will be vulnerable to delays in completion of nuclear units. Such delays could substantially enhance the attractiveness of short lead time, modular technologies in the region.

Mid-Continent Area Power Pool (MAPP-U.S.)



MAPP-U.S.

The U.S. members of MAPP presently rely on coal and nuclear power for the bulk of their electricity generation—20 percent nuclear, 66 percent coal; hydroelectric power supplies 14 percent. MAPP is expected to continue its reliance on these technologies through the 1990s. While oil and gas accounted for less than 1 percent of total generation in 1984 and are expected to supply about the same in 1993, installed nuclear capability in the region is expected to exceed oil and gas by less than 2 percent during the same time period.[50] This makes oil and gas "swing fuels" in the region, with all the associated implications for avoided cost rates.

Demand growth is predicted to increase at an average annual rate of 2.4 percent over the next 10 years; utilities within the region are planning an 11.5 percent increase in capacity levels by 1993.[51] DOE projections of reserve margins (which assume scheduled completion of all units planned as of the end of 1983) indicate the region may fall below traditional reliability criteria in the late 1980s and early 1990s (see table 7-4). In addition, figure 7-3 suggests shortfalls of the 20 percent reserve margin under all but the lowest national demand growth case. Since construction has not yet begun on roughly 50 percent of the plants scheduled to come on line after 1989,[52] system reliability concerns may create a window of opportunity for short lead-time technologies in the region.

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[46] Ibid.; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[47] Given projected shortfalls of some reliability criteria, this aim requires further explanation, which is found in the fact that MAIN's surplus is primarily confined to its offpeak (winter) season; shortfalls vis a vis the 5 percent adjusted reserve criterion are only expected in the summers of the years cited in table 7-4.

[48] MAIN utilities rely on intraregional transfers between MAIN subregions which have abundant coal and others which are either capacity deficient or oil and gas reliant (NERC, *14th Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983). If it finds itself in need of power (e.g., in 1984—see reserve margin section), imports can be gotten from MAPP and ECAR, and maybe also from SPP.

A recent study notes that MAIN's export capability to TVA (SERC) may be extremely low under anticipated 1988 peak conditions; export capability from MAIN to SPP and MAPP into MAIN under these projected conditions was judged inadequate (DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[49] DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993* , op. cit., 1984.

[50] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984; and NERC, *14th Annual Review*, op. cit., 1984.

[51] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[52] NERC, *14th Annual Review*, op. cit., 1984.

MAPP members echo the concerns of other coal-reliant systems regarding the potential impact of more stringent air quality controls. Besides impeding overall reliability, increasing maintenance needs, and spurring "premature" plant retirements, they think retrofits could also lead to higher electricity costs for consumers.[53]

While MAPP's member utilities will not be increasing their reliance on nuclear power, storage of spent fuel from existing plants is a concern for the 1990s because onsite storage capacity will be fully used by that time. If national nuclear waste repositories for away-from-reactor storage are not available, some member systems expect they may have to reduce generation from their nuclear units.[54] As in MAAC, this could create further need for new capacity.

The U.S. members of MAPP are summer peaking; its Canadian members are winter peaking. MAPP's U.S. members import power from its Canadian members, exchange power with neighboring council such as MAIN, and engage in a substantial amount of intraregional transfers available due to load diversity within the region. Studies are now underway regarding the feasibility of increasing the region's ability to import hydroelectric power from Manitoba into Minnesota and Wisconsin, and the Dakotas.[55] Given the usual economic attractiveness of such transactions, imports could emerge as a more cost-effective supply option than competing generating technologies if MAPP's import capabilities are increased.

Northeast Power Coordinating Council (NPCC-U.S.)

VT
NH
ME
MASS
RI
NEW YORK
CONN

NPCC-U.S.

More than 50 percent of installed capacity in NPCC is oil-fired. Oil accounted for 38 percent of total generation in 1984; it is expected to account for 21 percent in 1993. Nuclear units accounted for 16 percent of 1984 capacity and are expected to represent 23 percent by 1993 (23 percent and 38 percent of total generation, respectively), while coal-fired units accounted for 11 percent of 1984 capacity and are expected to contribute 17 percent by 1993 (18 and 27 percent of generation, respectively).[56]

Decreasing the region's heavy dependence on oil hinges on completion of several new coal and nuclear units ranging in size from 800 to 1,150 MW. Some of these plants have proven quite controversial. For example, two of NPCC's nuclear units—Shoreham and Seabrook I—are among the most expensive plants in the country, with installed costs of $5,192 and $3,913 per kilowatt, respectively.[57] Increased electric rates associated with bringing these plants into the ratebase could run as much as 53 percent for Shoreham (Long Island Lighting Co.'s service area) and 63 percent for Seabrook I (for Public Service of New Hampshire's customers).[58] If demand growth continues as predicted (1.7 percent) and if some of these new plants are not completed and brought into service during the 1985-90 time period, the opportunities for new technologies will depend to a large extent on their competitiveness with new oil-fired, conventional units. (As discussed below, imports from Canada are not likely to be able to fill the resulting demand for power.) Given the high population density of many NPCC States, modular technologies which are not land intensive might prove the easiest to site.

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[53] Ibid.

[54] Ibid.

[55] EIA, *Interutility Bulk Power Transactions*, op. cit., 1983; and NERC, *14th Annual Review*, op. cit., 1984.

[56] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[57] Cook, op. cit., Feb. 11, 1985.

[58] Ibid.

Cancellation of currently planned facilities could also adversely affect reliability criteria within the region. Given present plans to increase generating capability 14 percent over 1983 levels by 1993, it is expected that the systems within NPCC will meet traditional reliability measures into the 1990s. But problems are anticipated in mid-decade if these units are not brought on line, peak demand growth substantially increases beyond present forecasts, and/or presently operating nuclear units are not kept in operation.

On the other hand, if currently planned units come into service as scheduled, figure 7-3 suggests a shortfall of the 20 percent reserve margin in the early 1990s only under the 4.5 percent national demand growth scenario.

NPCC systems import power primarily from the Canadian NPCC systems and ECAR. Reliance on oil makes economy transfers especially attractive to NPCC members, but the demand for such transfers exceeds existing, under construction, and planned transmission capacity both within the United States and between NPCC's U.S. and Canadian members. Present economy energy transfer levels leave little capacity for emergency flows; if emergency transfers are needed, economy transfers will be reduced. Even NPCC's coal burning utilities buy economy power when possible, since they have large loads and heavy peaks which must otherwise be met with oil-fired steam and peaking units.[59]

Southeastern Electric Reliability Council (SERC)

KENTUCKY
VIRGINIA
NORTH CAROLINA
TENNESSEE
SOUTH CAROLINA
ALABAMA
GEORGIA
FLORIDA
MISSISSIPPI
SERC

SERC is characterized by a diverse fuel base which encourages heavy intraregional economy transfers as well as exchanges with interconnected systems in neighboring ECAR and SPP.[60] Regionwide, coal and nuclear plants accounted for 68 percent of 1984 installed capacity and 87 percent of total generation; 1993 projections call for continuation of these patterns.[61]

Twenty-two percent of the capacity in SERC is oil- or gas-fired. While these plants accounted for only 7 percent of total generation in 1984, this pattern varies markedly, with Florida's installed oil/gas capacity exceeding levels in the other SERC subregions by a factor of 5 or more.[62] Florida's reliance on oil and gas accounts for substantial intraregional economy transfers from other members of SERC, although transmission capacity constraints are limiting otherwise desirable transfers from hydroelectric and coal-fired generators in Alabama and Georgia.[63]

While Florida plans to decrease gas generation in 1993 to slightly less than 50 percent of 1984 levels, oil generation is expected to increase by 4 percent. The overall region is following a similar but less pronounced pattern; gas generation as a percent of total electricity generation is expected to decline by about 2 percent while oil generation increases about 1 percent.[64] Oil and gas costs and the availability of intraregional and interregional power will continue to be important factors affecting the relative economics of power supply alternatives in the region.

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[59] EIA, *Interutility Bulk Power Transactions*, op. cit., 1983; NERC, *14th Annual Review*, op. cit., 1984; and DOE, *Electric Power Supply and Demand for the Contiguous United States, 1984-1993*, op. cit., 1984.

[60] EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[61] NERC, *14th Annual Review*, op. cit., 1984.

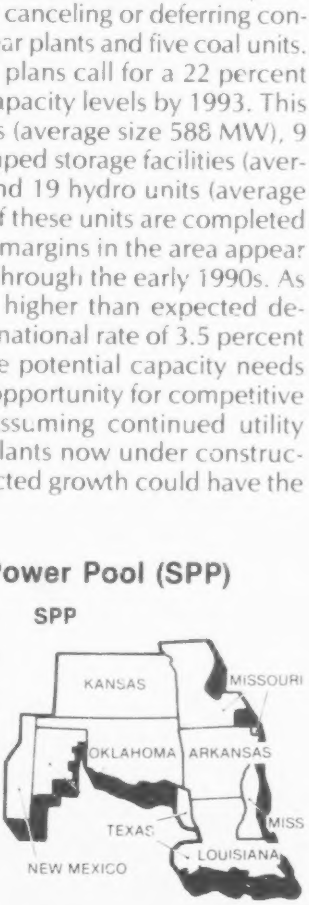
[62] Sixty-seven percent of 1984 installed capacity and 35 percent of total generation in Florida was oil- or gas-fired; by 1993, this is projected to decrease to 57 percent of capacity and 31 percent of generation.

[63] NERC, *14th Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[64] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

Predicted average annual growth in summer peak demand varies between SERC subregions from 2.6 to 3.8 percent. Increased conservation and load management, changing demand patterns, increased construction costs, and the addition of customer generation are cited by the council as reasons for canceling or deferring construction on five nuclear plants and five coal units. Current construction plans call for a 22 percent increase over 1983 capacity levels by 1993. This includes 23 coal units (average size 588 MW), 9 nuclear units, 13 pumped storage facilities (average size 207 MW), and 19 hydro units (average size 40 MW).[65] If all of these units are completed on schedule, reserve margins in the area appear more than adequate through the early 1990s. As figure 7-3 illustrates, higher than expected demand growth (e.g., a national rate of 3.5 percent or more) could create potential capacity needs in the region and an opportunity for competitive new technologies. Assuming continued utility commitment to the plants now under construction, lower than expected growth could have the opposite effect.

Southwest Power Pool (SPP)



Average annual peak demand growth predictions for SPP's three subregions for the 1985-93 planning period range from 1.1 to 6.1 percent. Overall, the region's 1984 generating capability was predominately oil, gas, and coal, with oil and gas accounting for 55 percent and coal accounting for 38 percent of installed capacity. The 1993 projections show oil and gas capability reduced to 44 percent and coal increased to 41 percent. Installed nuclear capacity—3 percent of total capability in 1984—is expected to increase to 10 percent by 1993.[66]

SPP joins SERC as one of the only regions projecting an increase in reliance on oil for generation (from 4 percent in 1984 to 8 percent in 1993). Actual and projected fuel reliance for electricity generation in the region emphasizes coal, gas, and nuclear fuels, with coal increasing from 51 percent in 1984 to 53 percent in 1993; gas decreasing substantially, from 36 percent in 1984 to 23 percent in 1993; and nuclear doubling from 7 percent in 1984 to 14 percent in 1993.[67]

Fuel reliance within SPP is variable between subregions, encouraging intraregional transfers from coal-reliant areas to those emphasizing oil or gas. Both the Southeast and West Central subregions are heavily reliant on oil and gas, although both plan to decrease capability and generation from these fuels as a fraction of total capability and generation by the 1990s.[68]

Member utilities in SPP are planning to increase 1993 installed capacity by 21 percent over 1983 levels. As figure 7-3 shows, these plans leave reserves above the 20 percent margin through 1993 under all but the high national growth scenarios (i.e., 3.5 percent or more). The majority of these new plants are coal or lignite (10,200 MW), but more than half of them (about 6,000 MW) were only in the planning stage as of January 1984. The remaining new plants are nuclear (5,700 MW) and peaking capacity (1,100 MW, mainly combustion turbines). If all of these plants are completed on schedule, the region will still be dependent on gas and oil (i.e., 44 percent of total planned capacity for 1993).[69] Delays could create potential opportunities for new technologies.

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[65] NERC, *14th Annual Review*, op. cit., 1984.

[66] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[67] Ibid.; and NERC, *14th Annual Review*, op. cit., 1984.

[68] For example, 73 percent of 1984 generating capability in the Southeast subregion was oil- or gas-fired; 46 percent of total generation was from gas. In the West Central subregion, 51 percent of installed capability was oil or gas in 1984; 43 percent of total generation was from gas. By 1993, oil-gas capability as a percent of total plant is expected to decrease to 56 percent in the Southeast subregion and 42 percent in the West Central subregion, with generation from gas sources also decreasing. Dependence on oil generation, while small, is expected to increase in both subregions—from 11 to 17 percent in the Southeast, from 0.05 to 1.5 percent in the West Central. In contrast, the Northern subregion expects generation from gas to remain around 5 percent from 1984 through 1993, with oil generation less than 1 percent; installed oil and gas capacity was 29 percent in 1984 and is projected at 25 percent in 1993. From NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

[69] NERC, *14th Annual Review*, op. cit., 1984.

As a hedge against possible oil and gas availability problems or price increases, member utilities are installing (or planning to install by the early 1990s) several new transmission lines to take better advantage of available economy power transfers from SERC, ERCOT, MAPP, and WSCC.[70] If new generating sources are needed, major factors affecting their comparative economics will include the price and availability of oil and gas, the regulatory climate affecting the region's coal plants, and the degree to which the promising cogeneration resource in Louisiana (see table 7-7) has been tapped.

Western Systems Coordinating Council (WSCC-U.S.)

WSCC
WASHINGTON
MONTANA
SOUTH DAKOTA
OREGON
IDAHO
WYOMING
NEVADA
UTAH
COLORADO
CALIFORNIA
NEW MEXICO
ARIZONA
TEXAS

Of all the NERC regions, subregional differences in generation mix are most pronounced in WSCC, where there are four separate power pools—the Northwest Power Pool, The Rocky Mountain Power Area, the Arizona-New Mexico Power Area (ANMPA), and the California-Southern Nevada Power Area (CSNPA).

Members of the Northwest Power Pool Area (NWPP) primarily rely on hydropower; by 1993 they expect 62 percent of total generating capacity to be hydroelectric, 23 percent to be coal-fired, 9 percent to be nuclear, and less than 5 percent to be gas or oil. NWPP utilities expect growing capacity contributions from cogeneration and small renewables, especially small hydroelectric plants owned by third parties. According to a recent NERC report, NWPP members are concerned that using power from these sources will require increased utility operating reserves to offset "the unpredictability of the generation magnitude and the difficulty in monitoring the output since utilities have no authority regarding the dispatch of these resources."[71] (See chapter 3 for a discussion of these issues.)

The planning projections for 1993 made by members of the Rocky Mountain Power Area (RMPA) continue the present emphasis on coal and hydroelectric sources, with gas and oil power accounting for about 8 percent of installed generating capacity and nuclear accounting for less than 3 percent. The emphasis shifts away from hydropower in the WSCC's other subregions. For example, the ANMPA expects continued dependence on coal and oil-gas generation (respectively 51 percent and 28 percent of projected 1993 installed capacity), with nuclear expected to supply about 16 percent. CSNPA remains the most heavily dependent on oil and gas of all the WSCC subregions, which helps to explain that area's continued encouragement of unconventional technologies through various State and utility commission policies. CSNPA member systems expect 41 percent of total 1993 generating capacity to be oil and gas, 24 percent to be hydropower, 13 percent to be nuclear, 11 percent to be coal, 5 percent to be geothermal, 4 percent to be cogeneration, and about 2 percent to be from other sources.[72] Recent trends in development of cogenerated power to be sold to California utilities may substantially diminish the market for power from other third party producers in the near term.[73]

Due to both generation mix differences and load diversity, there are high levels of intra-regional power transfers in WSCC, especially from regions rich in cheap hydroelectric or coal power to those relying on oil and gas. In particular, when water supply permits, oil- and gas-dependent California imports hydropower from the NWPP. Coal-burning States (Utah, Wyoming, and Arizona) sell power to the Pacific Northwest when water supplies there are low. The Southwestern States in WSCC also import power from the Pacific Northwest when it is available. Construction plans are underway to improve transmission capability within WSCC itself as well as among it and SPP, MAPP, and MAAC to take better advantage of economy power transfers. ANMPA members are especially interested in maximizing use of available transmission facilities because they are capacity rich and financially dependent on selling surplus power to other WSCC members. Presently, there are insufficient facilities in place to take full advantage of available economy power transfers; in particular, transmission capability is insufficient to meet the demand for such transfers into the California-Southern Nevada subregion and for transfers between the Rocky Mountain and Arizona-New Mexico subregions.[74]

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[70] Ibid.; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[71] NERC, *14th Annual Review*, op. cit., 1984, p. 58.

[72] NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984; and NERC, *14th Annual Review*, op. cit., 1984.

[73] For example, as of April 1985, Texaco and Chevron were each proposing to erect 1,200 MW of cogeneration capacity in the heavy oil fields in Kern County (total projected capacity of 1200 MW). Source: Burt Solomon, "Paradise Lost In California," *The Energy Daily*, vol. 13, No. 80, Apr. 26, 1985.

Predicted demand growth varies dramatically between WSCC subregions, with the predicted average annual increase in summer peak demand ranging from 1.9 percent (CSNPA) to 4.4 percent (ANMPA). If only 65 percent of the capacity presently planned to come on line in 1993 (41 percent coal and 34 percent nuclear) is actually built, member utilities expect that, while some reliability criteria may not be met, overall resources will be adequate as long as demand does not increase faster than currently projected.[75]

Alaska Systems Coordinating Council (ASCC)

Most of Alaska's population (i.e., 75 percent) resides in the "Railbelt" area stretching between Seward, Anchorage, and Fairbanks. Electricity in this region is provided primarily by indigenous natural gas, supplemented by coal, oil, and hydropower. The Railbelt is the only subregion interconnected by a common grid. If pending license applications with FERC for two hydropower projects are approved (Bradley Lake—90 MW, and Susitna—1,600 MW), ASCC expects the subregion will have sufficient capacity to meet expected demand past the year 2000.[76] It is doubtful that capacity credits for alternative technologies would be available in the near term under this scenario; the Railbelt's projected 1985 peak is 717 MW; the 1990 peak is expected to be 918 MW.[77]

While the technical and environmental concerns surrounding the Susitna Project appear resolved, its size and cost are controversial. In response, the State is proposing to build the project in stages, starting with 500 MW and eventually upgrading the facility to 1,600 MW.[78] FERC is not expected to make a licensing decision until sometime in 1986.[79]

The ASCC expects greater development of the Railbelt's indigenous coal reserves if Susitna is not approved, creating a potential opportunity for new coal technologies. In addition, there are pending applications for waivers of the Fuel Use Act's natural gas generation prohibitions to allow Railbelt utilities to take greater advantage of the State's natural gas reserves.

Southeastern Alaska is served primarily by Federal and State hydropower projects. The rest of the State—consisting of widely dispersed villages (the "bush")—obtains electricity from diesel-fueled generators. Access to many of these areas is difficult. The bush subregion appears to offer the best development potential for dispersed electric generating technologies in Alaska. Of the technologies considered in this report, wind turbines appear among the likeliest candidates. There also has been some development of photovoltaics (PV) in remote areas, and hybrid systems linking wind or PV with battery storage may prove attractive. For any new technologies considered for electricity generation in the bush, project economics will be strongly influenced by the Power Cost Equalization Program.

Diesel fuel costs in the bush are high, resulting in electricity costs of up to $1/kWh in some areas (e.g., where fuel has to be flown in). Electricity costs from 35 to 50 cents/kWh are typical. Under the Power Cost Equalization Program, these costs are subsidized by the State, so that village residents pay only a small fraction (in some instances, less than 9 cents/kWh for the first 750 kWh used each month) of the production cost of electricity.[80] The program is funded by royalties from oil sales.[81]

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[74] NERC, *14th Annual Review*, op. cit., 1984; and EIA, *Interutility Bulk Power Transactions*, op. cit., 1983.

[75] NERC, *14th Annual Review*, op. cit., 1984.

[76] Information provided to OTA by the Alaska Systems Coordinating Council (ASCC), a NERC affiliate, personal communication, May 1985.

[77] Ibid.

[78] Ibid.

[79] Vic Reinemer, "Electrifying Alaska," *Public Power*, November-December 1983, vol. 41, No. 6, pp. 10-19.

Outside of the comparative cost issues raised by present implementation of this cost equalization program, the main constraint on extensive wind development appears to be the absence of a grid allowing power transfers among villages and from dispersed sources to the State's major load centers. Obtaining third-party financing for small facilities could also be a problem, although the State has shown willingness to help facilitate new projects.[82]

Technical issues affecting wind development in the State include the substandard installation of many of the village diesel generator systems (e.g., systems with transmission lines running on the ground covered with wood boxes and/or generators housed in plywood structures susceptible to fire).[83] Gaining access to remote areas for construction and/or maintenance could also be a problem[84] for wind as well as any other technology.

The Alaska wind resource is especially attractive along the coast. The solar resource is strong but subject to extreme seasonal variation: in late winter, daylight is only available for 4 hours; in midsummer, light is available for about 20 hours. Geothermal resources are available on the Aleutian Islands, but there is no power transfer capability, either existing or planned, to transfer electricity from this area to the State's load centers, making substantial development of this resource for electricity generation unlikely.

Hawaii

The State of Hawaii is a chain of islands in the Hawaiian Archipelago. Most of the State's businesses and residents are on Oahu in or near Honolulu, the State capital. Oahu accounts for about 80 percent of Hawaii's peak electricity demand.

The State is served by a handful of investor-owned electric utilities relying almost exclusively on oil-fired capacity (99 percent of utility-owned generation in 1983 was oil-fired).[85] This generation is supplemented by seasonal purchases from third-party producers, most of which are sugar processing facilities cogenerating electricity from boilers fueled with bagasse, the pulpy residue from processing sugar.[86] Sugar is the State's main agricultural crop.[87] For approximately 48 weeks each year, firm power contracts from bagasse-fired cogeneration provide about 20 MW on the Big Island (expected 1985 peak demand for the island: 99 MW), 20 MW on Maui (expected peak demand: about 102 MW), and 15 MW on Kauai (expected peak demand: 40 MW). Oahu, with an approximate peak demand of 949 MW, has no power from these sources.[88]

Power contributions from sugar processors are not expected to increase substantially over the next decade due to economic uncertainties in the industry.[89] Significant increases in power contributions from other biomass fuels are not expected.[90]

While the islands are too new geologically to have indigenous fossil fuels and there are no known offshore oil reserves nearby, Hawaii has abundant renewable and geothermal resources. A recent study predicts that, by 2005, indigenous renewable resources could provide 90 percent of the island's electricity; each county has developed an energy plan aimed at decreasing dependence on imported fuels within cost and environmental constraints [91]

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[80] For the first 750 kWh used each month, the State picks up any additional charge above 8.5 cents, and below 52 cents, per kWh. Source: Information provided to OTA by Kinetic Energy Systems, an energy firm in Anchorage, AK personal communication, May 1985.

[81] Information provided to OTA by Polarconsult, an energy technology consulting firm in Anchorage, AK, personal communication, May 1985.

[82] Ibid.

[83] Ibid.

[84] Information provided to OTA by Independent Energy Producers, a California-based alternative technology trade association, personal communication, May 1985.

[85] Edison Electric Institute (EEI), *Statistical Yearbook of the Electric Utility Industry/1983* (Washington, DC: EEI, 1984).

[86] Many sugar plantations also generate hydroelectric power, but this is used mainly onsite for irrigation.

[87] The sugar industry accounts for 80 percent of the jobs on the neighbor islands to Oahu. Source: *Hawaii Integrated Energy Assessment* (HIEA), vol. I, prepared for U.S. Department of Energy by the Department of Planning and Economic Development, State of Hawaii; and Lawrence Berkeley Laboratory, University of California at Berkeley, June 1981.

[88] These peak demand figures are estimates for 1985 provided to OTA by the Hawaiian Electric Power Co., Inc., in June 1985.

[89] Information provided to OTA by the Hawaiian Electric Power Co., Inc., May 1985.

[90] *HIEA*, op. cit., 1981.

The State's solar resource is strong and consistent; the average insolation rate is higher than that of the mainland United States and there is also less seasonal variation.[92] Hawaii's wind resource is similarly promising; the northeast trade winds blowing across the islands offer one of the most consistent wind regimes in the world. Hawaiian Electric Renewable Systems, Inc.,[93] is installing fifteen 625-kW wind turbines on Oahu; these are scheduled to come on line by the end of 1985. There are also about 3 MW of wind capacity operating intermittently on the Big Island of Hawaii.[94] The State may also be the site of a DOE demonstration project for a multi-megawatt wind turbine (MOD-5B).

Most of Hawaii's energy resources are located far from the Oahu load center. High-temperature geothermal reserves are a case in point: the Puna resource on the Big Island of Hawaii is considered extensive enough to fulfill most of the State's power needs for decades to come.[95] However, presently there is no means of transferring power from the Big Island to Oahu. This lack of transmission capability is the single biggest impediment to development of the islands' indigenous energy resources.

Development of an interconnected power transfer system hinges on successful design and installation of an undersea transmission cable capable of withstanding greater pressures, and extending greater distances, than has been attempted before. To date, submarine cables have not been installed below a depth of 1,800 feet and the longest distance a submerged cable has covered is 80 miles. A cable linking Hawaii with Oahu would be submerged in a 150-mile wide, 7,000-foot deep channel (the Alenuihaha Channel). [96] One source estimates construction costs at anywhere between $250 and $600 million; this excludes the cost of research and development, which has been funded primarily by Federal sources.[97] Whether or not the cable will ultimately prove feasible, or affordable, has not been demonstrated. The research phase is expected to be finished in the late 1980s.[98]

Hawaii's dependence on imported fuel provides a strong incentive to develop its energy resources.[99] Solar, wind, and geothermal technologies are the most likely to be extensively developed;[100] batteries or fuel cells might offer some advantages but might be seen as undesirable if they continued the State's dependence on shipped-in fuels or materials. Switching to coal-fired technologies currently is unlikely given the land requirements for solid waste disposal, the resulting air quality impacts, and the lack of indigenous coal resources.

Load management is not a particularly attractive option for Hawaiian utilities since there is little incremental cost difference between their oil-fired generating units and there are no opportunities for off-peak, lower cost power purchases from neighboring facilities. System load factors have continued to improve since 1979, however, due to decreased electricity demand.[101] Load growth is expected to be minimal on Oahu; the neighboring islands may experience 2 to 5 percent annual growth, but this is from very small peak demand levels to begin with.[102]

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[91] Ibid.

[92] John W. Shupe, "Energy Self-Sufficiency for Hawaii," *Science*, vol. 216, June 11, 1982, pp. 1193-1199.

[93] A subsidiary of Hawaiian Electric Power Co.'s parent company, Hawaiian Electric Industries.

[94] Information provided to OTA by Hawaiian Electric Power Co., Inc., May 1985.

[95] *HIEA* (op. cit., 1981, p. 41) estimates the Puna resource at 100 to 3,000 MW centuries; other sources estimate it at 1,000 to 5,000 MW (information provided to OTA by Hawaiian Electric Power Co., Inc., May 1985).

[96] *HIEA*, op. cit., 1981.

[97] Information provided to OTA by the Hawaiian Electric Power Co., Inc., May 1985.

[98] Cable feasibility studies are progressing; a tentative cable design has been selected, test protocol are being developed, and the requirements of handling line installation and maintenance at sea are being studied.

[99] As of 1984, the State's average residential electricity rates were the highest in the United States (i.e., 11.4 cents/kWh based on 750 kWh): Energy Information Administration, *Typical Electric Bills, January 1, 1984* (Washington, DC: U.S. Department of Energy, December 1984), DOE/EIA-0040(84). Residential rates vary substantially between the islands; e.g., in 1982 electricity cost were 11.4 cents/kWh in Honolulu (Oahu), while rates on Molokai were more than 19 cents/kWh (Shupe, op. cit., 1982).

[100] Potential contributions from OTEC systems may be substantial in the long run, but the technical and economic issues associated with this technology make it an unlikely candidate for development in the 1990s.

[101] Information provided to OTA by the Hawaiian Electric Power Co., Inc., May 1985.

The State's economy is heavily dependent on tourism and agriculture. Land values are at a premium, and Hawaii has strict zoning laws to protect its agricultural and recreational lands.[103] Development of the land-intensive solar and wind technologies to meet the State's electric power needs will definitely be affected by these factors. But the lack of transmission capacity between the islands poses the most immediate impediment to substantial development.

SUMMARY OF MAJOR REGIONAL ISSUES

Demand Uncertainty

Future electricity demand and the inherent uncertainty associated with estimating it are two of the most important factors affecting utility choices between electricity supply options. Predicted electricity demand growth rates differ dramatically within and among regions, and unanticipated changes in these predictions could substantially affect both overall system reliability and the need for new generating capacity. Traditional reliability measures such as generating reserve margins are very sensitive to demand predictions. This sensitivity is especially high in regions where substantial numbers of new coal and nuclear plants are under construction. In the long run, consumer reaction to the cumulative "rate shock" associated with bringing such large plants into the ratebase may increase utility commission actions encouraging greater reliance on alternative supply options.

The 1993 capacity levels in four NERC regions are expected to exceed 1983 levels by more than 20 percent; for three of these regions—ERCOT, MAIN, and SPP—this entails an increase of more than 75 percent in installed nuclear capacity. The oil-dependent NPCC region will be increasing its coal capability by similar percentages, although its overall capability increase over 1983 levels will be below 20 percent. If demand increases faster than predicted and construction delays occur, reserve margins in some of these regions may be adversely affected. If demand growth predictions have been overestimated, construction plans may have to be altered, with uncertain effects on the financial status of the utilities affected.

Present and Projected Fuel Reliance

Capacity needs and the relative attractiveness of available supply options are also strongly influenced by regional fuel and technology reliance, since these plant characteristics generally establish the benchmarks for technology cost comparisons. While most systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, reliance on premium fuels is expected to be strong enough in ERCOT, MAAC, NPCC, and some subregions of SERC, SPP, and WSCC that the economics of competing technologies will remain very sensitive to the price and availability of oil and gas.[104] This will apply even more strongly in the Florida subregion of SERC, the Southeast subregion of SPP, and the Arizona-New Mexico subregion of WSCC where, due to predictions of high demand growth and continued decreases in (or stabilization of) oil prices, reliability councils are forecasting increased dependence on oil. Regions characterized by heavy reliance on coal or nuclear power will be vulnerable to changes in present environmental regulations; the ultimate effect of regulatory changes will vary between utility systems and may create the need for additional power sources in some areas.

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[102] Estimates provided to OTA by the Hawaiian Electric Power Co., Inc., May, 1985.

[103] *HIEA*, op. cit., 1981

[104] These fuel reliance projections are from NERC, *Electric Power Supply and Demand, 1984-1993*, op. cit., 1984.

Plant Life Extension

Over the next several decades, the age of existing generating facilities is likely to influence the need for new capacity because construction may be deferred if scheduled retirement of aging powerplants can be delayed by plant rehabilitation or efficiency improvements. Deferral prospects vary considerably by region. By 1995, approximately 40 percent of the fossil steam generating plants in MAIN, NPCC, and WSCC will be over 30 years old; many of these plants may be promising candidates for life extension. In terms of total installed capacity, the opportunities for life extension will be greatest in ECAR, SERC, SPP, and WSCC. In all regions, the degree to which this option is exercised will be heavily influenced by the comparative economics of other supply alternatives.

Other Key Variables

Opportunities for increased economy power transfers between and within regions are found to be attractive to a majority of utilities, but existing and planned transmission capacity will limit these transfers.

The potential for cogeneration tends to be State specific; opportunities are proving particularly strong in the Gulf States, e.g., Texas and Louisiana, and in California. These systems will often be in direct competition with the new technologies considered in this assessment.

Load management appears attractive in all regions, although peak reduction in oil-dependent systems could prove counterproductive in the long run if it defers replacement of costly peaking units.

Conservation is similarly attractive, although the resource is both difficult to define and tap completely.

Land and/or energy resource availability constraints are expected to limit development of geothermal, wind and solar technologies in some regions.

Utility economic and financial characteristics are so variable within as well as among regions that no clear regional generalizations are drawn.

Generalizations about regional regulatory characteristics prove similarly difficult, although the policies of some innovative utilities commissions are creating more favorable environments for new technologies than might otherwise be the case in their jurisdictions. In addition, given siting experiences to date, it seems reasonable to expect that developers of new technologies may experience permitting delays as localities adjust the regulatory process to accommodate new electric generating systems.

Chapter 8

Conventional v. Alternative Technologies: Utility and Nonutility Decisions

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Chapter 8

Conventional v. Alternative Technologies: Utility and Nonutility Decisions

INTRODUCTION

Deployment of the technologies addressed in this assessment in the 1990s hinges on investment decisions made by both electric utilities and nonutility power producers. They are the primary (and in some cases, the only) markets for these new technologies. Their investment decisions will determine the future commercial viability of the technologies. Investment in these technologies will only occur if they can compete with existing electricity-generating technologies. In addition, the new technologies will have to compete amongst themselves for limited sources of capital.

This chapter focuses primarily on the process of technology choice by utilities and nonutility entities, and the relative economics of the various new generating technologies. The first and second sections discuss these issues for utilities and nonutilities. The third section provides cross-technology comparisons on issues concerning deployment, environmental impact, and ease of siting. Emphasis in the latter section will be on the nonquantifiable issues which cannot be addressed in cost and profitability calculations.

UTILITY INVESTMENT IN POWER GENERATION

Overview

Electric utilities in the United States are regulated to meet customer electricity demands at all times with reliable and reasonable cost power. If customer demand increases, sufficient generating capacity must be available. Utility planners attempt to examine all options available to them to meet this demand; traditionally, the least cost option—or at least what was thought to be least cost—has been the preferred option. Recent demand and operating cost uncertainties have forced the consideration of other investment criteria, e.g., financial health, and has complicated the traditional decisionmaking process. This section focuses on electric utility decisionmaking and, using the methodology of the utility decisionmaking process, compares new technologies and load management with traditional utility options such as conventional pulverized coal-fired plants and utility-owned combustion turbines.

Utility Decisionmaking

Electric utilities operate under a different set of decision rules and constraints than other businesses (see box 8A for a brief description). In return for the privilege to operate as a monopoly, investor-owned electric utilities are subject to government regulation of prices, profits, and service quality.[1] Because of this regulation, utilities cannot maximize profit. For example, a utility must install added capacity to meet increased de-

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[1] Publicly owned utilities are also subject to governmental control and oversight of utility operations and finances. The source of control can be municipal government, local entities, or the Federal Government. Since investor-owned utilities (IOU) account for the majority of U.S. energy sales to ultimate customers (76 percent—see table 7-1), emphasis will be placed on IOU decisionmaking. Moreover, many publicly owned utilities, primarily municipally owned utilities, are distribution-only utilities and do not invest in powerplants. Nevertheless, these municipal utilities will be very interested in demand side alternatives, e.g., load management.

Box 8A.—Traditional Industrial Investment Decisionmaking

Traditional industrial investment decisions can generally be characterized as based on maximizing profits within a specific budget constraint. From a collection of different capital projects (e.g., plant expansion, new product line, etc.), an optimum mix of projects is chosen to maximize the value of the firm. Standard discounted cash flow techniques are used to develop measures of this value, such as the net present value, the internal rate of return, or the payback period. Brief definitions of these terms are:

- *Net Present Value:* The net present value is equal to the present value of future returns, discounted at the marginal cost of capital, minus the present value of the cost of the investment.
- *Internal Rate of Return:* The rate of return on an asset investment. The internal rate of return is calculated by finding the discount rate that equates the present value of future cash flows to the cost of the investment.
- *Payback Period:* The length of time required for the net revenues of an investment to return the cost of the investment.

Industrial firms also often use a minimum acceptable rate of return (or "hurdle rate") for screening alternatives. The level of the hurdle rate varies in direct proportion to the level of risk involved in the investment.

SOURCE: J. F. Weston and E. F. Brigham, *Managerial Finance*, 6th ed. (Hinsdale, IL: The Dryden Press, 1978).

and, even though it may decrease profits.[2] Electric utilities have a legal obligation to serve all the demand of their customers at any time.[3] Utilities normally construct enough extra capacity to provide a reserve margin against the possibility of being unable to serve customer load if a generating unit fails.

Utility decisionmakers also have obligations: 1) to ratepayers to minimize their rate burden over time, and 2) to their stockholders to maximize the utilities' financial health. The accepted means of accomplishing this is to minimize costs within reliability, regulatory, environmental, and financial constraints.[4]

Utility Planning Process

Electric utility decisionmaking on new plants is a four-step process: load forecasting, generation planning, transmission planning, and distribution planning. Table 8-1 lists the different characteristics of these power planning functions. The first step, load forecasting, determines the need for additional plants. Typical forecasting techniques include time series analysis, econometric modeling, and end-use models. In the past, utilities could rely on simple trend analysis to project future demand based on past growth rates, e.g., 7 percent a year. Recent unpredictable demand growth, however, has made this method undependable and more sophisticated methods are gaining wider acceptance.

Generation planning focuses on two important questions: the capacity needed for adequate reserve margins and the mix of capacity needed for least cost operation. Capacity expansion models are used to examine possible generation alternatives and to determine the least costly mix of future generation additions. Next, the operation costs and reliability of this generation mix are examined. Finally, the impact of the candidate capacity plan on the utility's financial position is assessed. These modeling and analysis functions often rely on complex optimization and simulation models.[5] Transmission and distribution plan-

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[2] G.R. Corey, "Plant Investment Decision Making in the Electric Power Industry," *Discounting for Time and Risk in Energy Policy*, Robert C. Lind (ed.) (Baltimore, MD: Resources for the Future/Johns Hopkins, 1982), pp. 377-403.

[3] Garfield and Lovejoy provide a good summary of this obligation: "public utilities are further distinguished from other sectors of business by the legal requirement to serve every financially responsible customer in their service areas, at reasonable rates, and without unjust discrimination." (P.J. Garfield and W.F. Lovejoy, *Public Utility Economics* (Englewood Cliffs, NJ: Prentice-Hall, 1964), p. 1.

[4] A large body of economics literature is devoted to the incentive (or lack of incentive) for cost minimization under rate of return regulation. The seminal piece by H. Averch and L. Johnson (H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, vol. 52, No. 6, 1962, pp. 1053-1069) argues that rate-of-return regulation provides an opposite incentive towards capital maximization.

[5] Good reviews of generation planning models have been done by S. Lee, et al. (S. Lee, et al., *Comparative Analysis of Generation Planning Models for Application to Regional Power System Planning* (Palo Alto, CA: System Control, Inc., 1978); and D. Anderson (D. Anderson, "Models for Determining Least Cost Investment in Electricity Supply," *Bell Journal of Economics*, vol. 3, spring 1972).

Table 8-1.—Typical Power Planning Functions

Tasks	Primary considerations	Data requirements	Major outputs and objectives	Typical plan horizon
Load forecasting: • Energy forecast • Peak demand	• Changing weather patterns • Short/long-term trends in national/local economic variables • Changes in energy consumption patterns from: —Load management —Conservation —New technologies	• Historical consumption data • Weather data • Economic data —GNP —Employment —Many others • Appliance use data	• Short- and intermediate-range energy forecasts for cash management, financial planning, construction planning, and distribution planning • Long-range energy sales forecast for use in selecting generation equipment mix, timing, and characteristics • Short and intermediate peak demand forecast for interconnection/purchase power requirements • Long-term peak demand forecasts	Short: 0-1 year Intermediate: 1-5 years Long: 10-30 years
Generation planning: • Capacity studies • Production costing • Investment analysis • Siting studies	• System reliability • Pool requirements • New energy conversion technologies/costs • Capital availability • Regulatory requirements	• Peak load • Energy sales • Capital/equipment costs • Equipment operating and maintenance characteristics • Fuel costs • Construction cost "S" curves (expenditure patterns)	• Selection of site size, timing, and energy conversion technology for energy supply • Location of facility	10-30 years
Transmission planning: • Load flow studies • Stability studies	• System reliability • Changes in major load center locations • Interconnection requirements	• Energy sources • Load flows • Load stability	• Location, size, and timing of transmission facilities to support system needs	2-10 years
Distribution planning: • Substation • Major distribution	• Changes in service area growth patterns	• Load growth by area • New developments • Major industrial customers	• Location, size, and timing of new substation and major distribution lines	1-3 years

SOURCE: Theodore Barry & Associates, *A Study of the Electric Utility Industry* (Los Angeles, CA: Theodore Barry & Associates, 1980).

ning activities are used to assure system adequacy and reliability given projected demand and generation facility location.

In the past, this planning process was straightforward—electric demands could be predicted accurately and generation planning was not unduly hampered by financial and environmental constraints. The situation is now considerably changed. A survey of electric utility executives[6] indicates that the following major changes have affected their planning function the most in recent years: unpredictable demand growth, longer lead-times, and uncertain technology costs. Chapter 3 discusses these changes in depth.

These new factors have complicated the utility planning process. Utilities are required by Federal statutes, regulatory commissions, consumers, and stockholders to investigate all the possible costs and consequences, e.g., environmental impacts, of a generation alternative prior to investment. Consideration of many of these factors has been incorporated into structured regulatory proceedings like powerplant siting, but many of the issues and consequences can only be included in utility decisionmaking through judgments made by utility executives and planners. The current inactivity in new plant construction start-ups is due in part to the reluctance of utility decisionmakers to make these judgments. These factors are discussed in greater detail in subsection entitled *Required Project Characteristics*.

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[6] Theodore Barry & Associates, *A Study of the U.S. Electric Utility Industry* (Los Angeles, CA: Theodore Barry & Associates, 1980), p. IV-6.

Comparative Analysis

As mentioned earlier, unlike unregulated firms, utilities have not based their investment decisions strictly on profit maximization. Instead, they have traditionally examined all available[7] means of meeting customer demand (both generation and demand-side options) and then selected the alternative that is least costly in terms of the revenue required from the consumers. This comparison approach, known as the minimum revenue requirement approach, is derived from standard utility rate-making techniques (see box 8B). It has been used throughout the industry.[8] One recent survey indicated that 91 percent of investor-owned electric and combination electric and gas systems used a minimum revenue requirement approach.[9]

In this analysis, the comparative costs of the new technologies and of the conventional alternatives were arrived at by applying the minimum revenue requirement concept to each investment alternative and then deriving its levelized cost. OTA staff developed a cost analysis model using standard utility accounting and investment decision methodologies for comparison purposes.[10] This model projects yearly revenue requirements, i.e., costs, taxes, and allowed rate of return, for the expected life of a new plant. Levelized costs in cents per kilowatt-hour are derived from this revenue requirement stream, and form the basis of cross-technology cost comparisons. (Appendix 8A discusses the levelized cost estimation in much greater detail.)

Box 8B.—Rate-Making Fundamentals

The primary form of public utility regulation is the determination of the rates utilities can charge for their services. State public utility commissions (PUCs) traditionally have controlled rates for intrastate sales of electricity, while the Federal Government has had jurisdiction over sales for resale in interstate commerce since 1935.

Determining the rates a utility charges for its services is a two-step process. The PUC must decide first, how much money the utility needs (the revenue requirement) and second, how those funds will be collected (the rate structure or rate schedule). A utility's revenue requirement is the total number of dollars required to cover its operating expenses and to provide a fair profit. The revenue requirement is usually expressed in a formula such as the one that follows:

$$RR = E + d + T + (V - D)R$$

where:

RR = revenue requirement
E = operating expenses (e.g., fuel, maintenance, and insurance)
d = annual depreciation expense
T = taxes, including income taxes
V = gross valuation of the property serving the public
D = accrued depreciation
R = rate of return (a percentage)
$(V-D)$ = rate base (net valuation)
$(V-D)R$ = profit, expressed as earnings on the rate base, plus interest on debt

The revenue requirement is then distributed among the various groups or classes of customers in a fair and reasonable manner. Each class' cost to serve must be transformed into a rate design, a price which, when applied to the units of utility services billed, will produce revenue sufficient to cover the class cost to serve and in turn the overall revenue requirement.

Basic Assumptions

In order to compare different technologies on a consistent basis, several assumptions had to be made. The technologies considered for utility investment were assumed to be electric-only technologies—no cogeneration technologies were considered. Cost estimates calculated in this model were made on a constant dollar (1983) ba-

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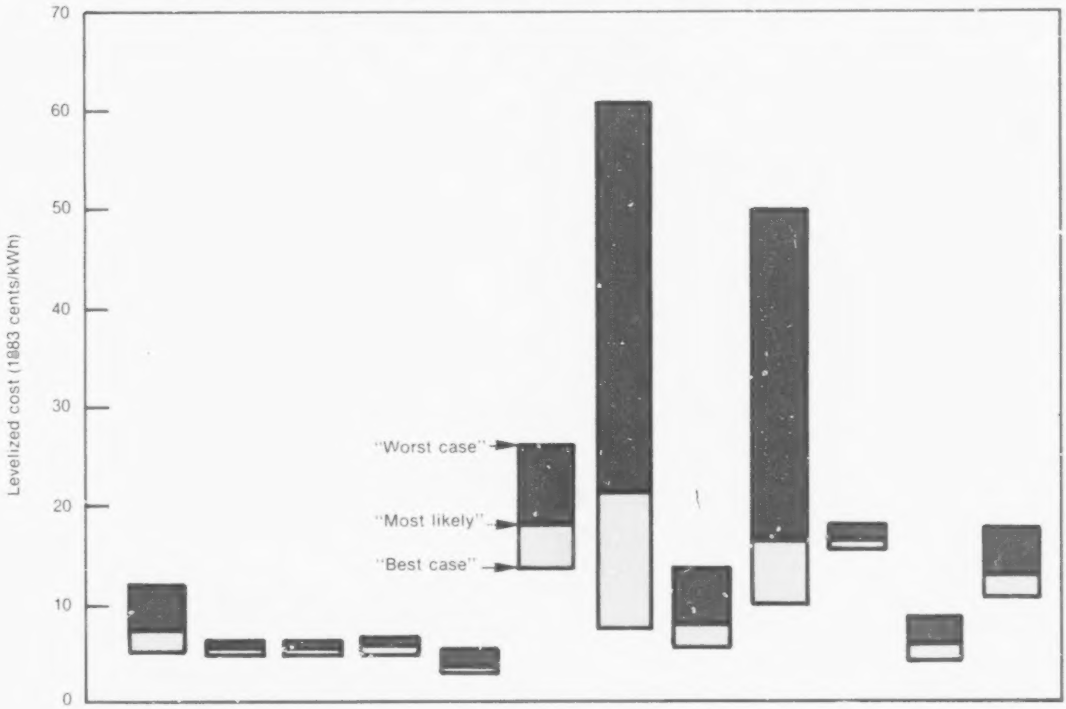
[7] "Available" in this context refers to the technologies utilities perceive as being able to meet their needs. The utility planners may feel that adequate information on a technology or commercial demonstrations are not sufficiently available for new technologies, and will not consider the technology.

[8] Publicly owned utilities perform a similar comparison. The components of revenue requirement will be different—reflecting factors such as rate of return.

[9] G.R. Corey, "Plant Investment Decision Making in the Electric Power Industry," op. cit., 1982.

[10] The analysis structure used to develop the OTA model was derived from the techniques used by Philadelphia Electric Co.'s Rates Division (Philadelphia Electric Co., *Engineering Economics Course* (Philadelphia, PA: Philadelphia Electric Co., Rates Division, Finance and Accounting Department, January 1980), p. 2-2.).

Figure 8-1.—Technology Cost Range: Utility Ownership—West



	Geo-thermal	AFBC	IGCC	Coal	Life ext (coal)	Solar parabolic dish	Photo-voltaics	Wind	Fuel cell	Com-bustion turbine	Battery storage	CAES
Size (MWe)	50	150	500	500	537	10	10	20	11	150	20	220
Cap cost ($/kW)[a]	1450	1420	1275	1474	400	2500	2633	1050	1430	350	500	582
Capacity factor	70%	70%	70%	70%	70%	25%	35%	30%	25%	10%	N/A	N/A
Levelized cost[b]	7.41	5.42	5.21	5.53	3.25	17.26	20.52	7.13	15.28	15.40	6.20	11.73

NOTE: **Basic assumptions** — discount rate: 5% (real), debt interest rate: 5% (real), base year dollars: 1983, Federal tax rate: 46%, Federal depreciation: 10- and 15-year ACRS; State tax rate: 9.6%; Insurance rate: 0.25% of capital cost; property tax rate: 2.3% of capital cost; Investment Tax Credit: 10%; debt portion: 50%; gas price escalation: 2% per year; oil price escalation: 2% per year; coal price escalation: 1% per year.

[a] Represents instantaneous capital cost in 1983 dollars.

[b] Levelized busbar cost under most likely cost and performance scenario.

SOURCE: Office of Technology Assessment.

sis. This allows the comparison of technologies with different reference years, lead-times, and lifetimes. Figure 8-1 lists the basic parameters that are assumed not to vary across technologies. Later in this section, the sensitivity of the costs to changes in these parameters will be addressed.

For the basic cost comparison, the technologies were examined for three scenarios: worst case, most likely case, and best case. These scenarios were derived from the parameter ranges included in the cost and performance projections developed in chapters 4 and 5. The worst case scenario incorporates the "worst" (most pessimistic) values for each parameter, while the best case uses the "best" (most optimistic) values. For example, the worst case uses the high end of the capital cost range, but uses the low end of the capacity factor range. In addition, the worst case scenario assumes little improvement in current technology conditions. Comparison of the worst and best case scenarios provides a range of levelized costs. The most-likely case numbers represent OTA's best estimates of future utility costs.

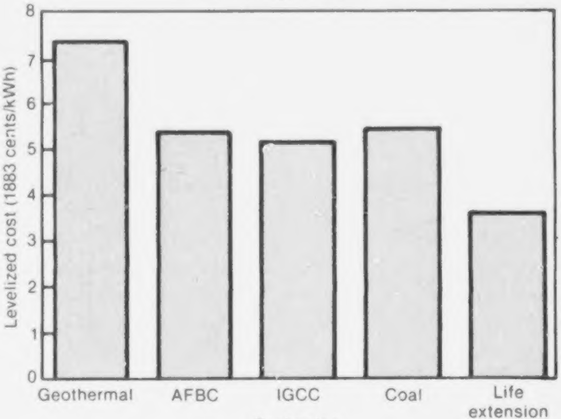
Cross-Technology Cost Comparison

The results of the comparative cost analysis are shown in figure 8-1. Costs for pulverized coal-fired plants, combustion turbines, and coal plant life extension were included for comparison purposes.

One of the striking features of the results shown in figure 8-1 is the wide cost ranges for solar photovoltaics and fuel cells. Both of these technologies are currently in early stages of development relative to the other technologies in the figure and are currently not competitive with other technologies. Nevertheless, as figure 8-1 shows, these technologies have the potential of significant cost reductions, and they could compete with peaking technologies, e.g., combustion turbines, or even base load technologies. To become competitive, however, they must be deployed in significant numbers, and important research development, and deployment questions must be resolved (see chapter 4).

Comparison of the new base load technologies—geothermal, atmospheric fluidized-bed combustors (AFBC), and integrated coal gasification/combined-cycle (IGCC)—with the primary conventional alternatives—pulverized coal-fired plants with flue gas desulfurization (FGD) and existing coal plant life extension- indicates that all of these new technologies are likely to be competitive with current technology in the 1990s. Figure 8-2 shows levelized costs for each of these technologies under the most likely case. These results indicate that coal powerplant betterment is the cheapest source of base load power. Among the new technologies, IGCC appears to be the best competitor followed by AFBC. The competitiveness of these new "clean coal" technologies is important because both produce less negative environmental impacts than conventional coal-burning technologies. The potentially attractive economics of the plant betterment option, however, could lead to extended use of old, dirtier coal plants, many without scrubbers. Geothermal plants are also attractive in terms of comparative cost, but the site-specific nature of geothermal power will probably limit widespread deployment.

Figure 8-2.—Base Load Technology Costs: Utility Ownership—West



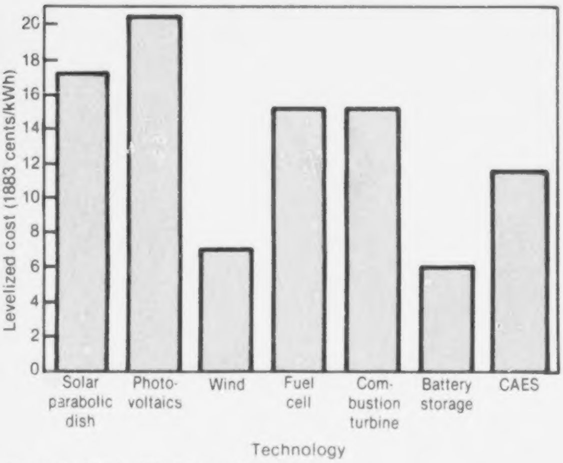
SOURCE: Office of Technology Assessment.

The new, intermittent, and peaking technologies addressed in this assessment are also expected to compete favorably with current technologies in the 1990s. Figure 8-3 shows the most likely-case costs for solar thermal electric, solar photovoltaics, wind, fuel cells, battery storage, and compressed air energy storage (CAES), as well as the most likely costs for combustion turbine powerplants. Wind power from utility-owned small turbines (<400 kW) in wind farms shows the lowest cost among the new generation technologies. The expected future levelized cost of wind technology is significantly lower than the other non-base load technologies. Wind also has the potential of competing with the base load technologies (see figure 8-2). The relatively low cost estimates for the storage technologies indicate that these technologies could compete favorably with peaking technologies to satisfy peak electric loads.

Sensitivity to Uncertainty

Despite the optimism reflected in the cross-technology comparison, the projections of these future costs for the new technologies are subject to a great deal of uncertainty. This uncertainty is reflected in the levelized cost ranges in figure 8-1. Several of the technologies—solar photovoltaics, wind and fuel cells—show particularly wide

Figure 8-3.—Peaking/Intermittent Technology Costs: Utility Ownership—West



SOURCE: Office of Technology Assessment.

cost ranges. Unless resolved, this uncertainty, and the investment risk it represents, will probably hamper widespread deployment of many new technologies well into the 1990s.

A sensitivity analysis was performed for each technology considered in this assessment. This analysis highlights the most sensitive parameters and provides insight into the technological developments that could produce the most improvement in future cost and performance. The sensitivity of a technology's levelized cost to changes in key parameters—capital cost, operation and maintenance (O&M) cost, capacity factor, and fuel cost—was tested by varying each parameter above and below the base case estimate by 25 percent. This analysis indicates, for example, that a 10-percent increase in wind farm capital cost could cause our most likely estimate of utility levelized costs to increase 1.5 cents/kWh or about 21 percent.

In general, the results of sensitivity analyses for all the technologies indicate that the three most critical parameters are capital cost, capacity factor, and fuel cost. The capacity factor is the most critical parameter for electric utility operation. Fuel costs were also very important for nonsolar technologies, but capacity factor consistently produced the largest variations in levelized costs. A somewhat surprising result from the analysis was that capital cost changes do not produce as much variation as these other parameters. Nevertheless, the relative importance of each of these parameters varies according to duty cycle, heat rate, and capital intensiveness. For example, fuel costs are the most sensitive parameter for combustion turbines, but capacity factor is more important for fuel cells. This is because of the lower capital costs and higher heat rates of combustion turbines.

A possible explanation for the relative importance of capacity factor vis-a-vis capital cost is found by examining the levelized cost formula.[11] The numerator of the formula is the levelized annual revenue requirement. The denominator is average kilowatt-hour production. Increases in capacity factor will directly increase electricity production and reduce levelized costs. Capital costs are recovered through economic depreciation over a number of years (15 years under present tax law). The levelization calculation discounts the depreciation costs more in later years than in early years. Thus, changes in initial capital cost do not produce as significant and direct an effect. This suggests that utilities are likely to continue to be very concerned with the availability and reliability of future generating options since these factors cause significant levelized lifecycle cost uncertainty.

Utility Strategic Options

Most utilities have put off decisions on new, large coal or nuclear plants. To commit large sums of capital to such long lead-time projects in the highly uncertain investment environment which has prevailed in this industry since the 1970s, they think, is too financially risky. Instead, many utilities are considering a variety of strategic options that will defer the need for such large-scale commitments. Chapters 3 and 5 discuss these options in detail. The discussion that follows focuses primarily on three of these options, namely life extension and rehabilitation of existing generating facilities, increased reliance on load management, and construction of small modular plants.

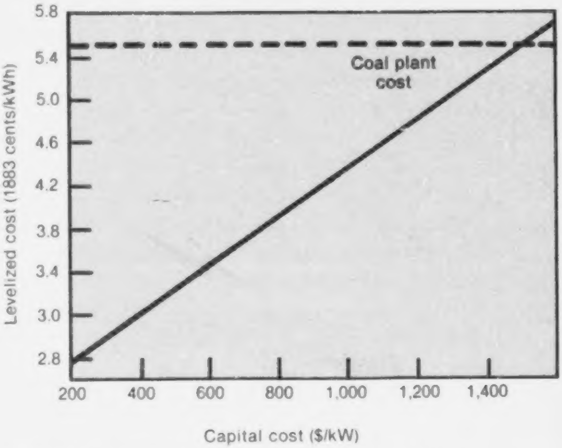
---

[11] The general form of the levelized cost formula is:

$$\frac{\text{levelized annual revenue requirement}}{\text{average annual electricity production}}$$

Plant betterment—i.e., life extension and rehabilitation of existing generating facilities—is a way to defer new generation investment. The capacity base for this option is sizable— by the year 2000, nearly a third of the existing U.S. fossil generating capacity will be more than 30 years old. In addition, the capital investment required—$200 to $800/kW—is relatively small. The attractiveness of this option is partially explained by its low expected levelized cost. As can be seen in figure 8-2, the expected costs of existing coal plant betterment are lower than both conventional and new base load generating technologies. Moreover, figure 8-4 shows that capital cost levels for life extension up to $1,500/kW can produce lower cost power than conventional pulverized coal plants with FGD, or an IGCC plant. Additional OTA modeling efforts[12] using EPRI Regional Systems data[13] indicate that at the system level, at least in the Southeast, fossil life extension (coal, oil, and gas-fired units) could produce overall utility system revenue requirements[14] as much as 5 percent lower than a capacity expansion plan based on large unit construction (the base case) to meet the same load. Nevertheless, the results also indicate that focusing plant betterment activity solely on oil and gas units could produce higher revenue requirements than the base case.[15]

Figure 8-4.—Life Extension Costs: Sensitivity to Capital Cost



NOTE: Assumes 537 MW plant size after life extension (7.5 percent capacity increase), 2-year lead time, 20-year lifetime, 70% capacity factor, 9.5 mills/kWh O&M cost, and a 9,106 Btu/kWh heat rate (5% efficiency increase). All other parameters are the same as listed in figure 8-1.

SOURCE: Office of Technology Assessment.

Load management is the other primary nongeneration option available to utilities. Its principal goals are to permit a higher proportion of demand to be served by lower cost electricity (from base load sources) and to defer the need for new generating capacity. There is the potential for sizable amounts of load management in the United States. For example, in the Southeast, a 5.4 percent potential peak load reduction in the summer and 3.3 percent in the winter appears possible.[16] Further analysis of these load management projections for the full EPRI Southeast Region typical utility by OTA indicates that load management could reduce future utility revenue requirements by up to 1.5 percent. At this level of peak reduction, the greatest reduction in revenue requirements is achieved by: 1) shifting the energy avoided at the peak to off-peak periods, and 2) coupling load management to the early retirement of oil and gas units.[17] While these results suggest net benefit from load management for the region, results for individual utilities or other regions may be different.

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[12] A state-of-the-art utility simulation model, the Utility System Analysis Model (USAM) by Lotus Consulting Co., was used for this analysis.

[13] Electric Power Research Institute, *The EPRI Regional Systems* (Palo Alto, CA: Electric Power Research Institute, July 1981), EPRI P-1950-SR. The load and system data used by OTA were the basic EPRI typical utility data sets that were modified by Lotus Consulting Co. to include plant additions.

[14] This value refers to a levelization of the utility system revenue requirements (using a 5 percent discount rate) over the 10-year period between 1990 and 2000.

[15] The assumptions used in this analysis were: 1) all plants which are 25 to 35 years old in 1985 through 2000 will have their life extended; 2) plant efficiency is increased by 5 percent, capacity is increased by 5 percent, and 10 years are added to design plant lifetime; 3) the plant betterment costs $200/kW (based on the new plant size); and 4) future capacity is deferred to achieve the same reserve margins as in the base case.

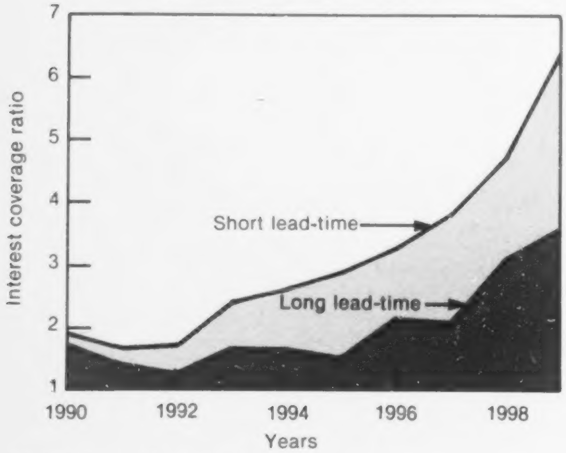
[16] Electrotek Concepts, Inc., *Future Cost and Performance of New Load Management Technologies*, final report to the Office of Technology Assessment, January 1985, OTA Solicitation US-84-7. For the Southeast, 5.4 percent reduction equals 891 MW in 1990.

[17] The basic assumptions used in this analysis are the same as for the plant betterment analysis. The capital costs of the utility load management program (calculated by Electrotek to be $191/kW) are annualized and expensed over the life of the equipment. Further analysis by OTA has shown that utility revenue requirements do not significantly differ when expensing or capitalizing the load management program.

Comparison of the results for the plant life extension and load management cases in a typical Southeast utility indicates that plant life extension is the more attractive option at currently projected load management levels and assumed program costs.

Of particular interest to many utilities are the potential benefits of increased flexibility and financial performance offered by **small-scale, short lead-time generating plants**. OTA modeling studies indicate that under uncertain demand growth, the cash flow benefits of such plants in the short term could be considerable.[18] For example, as shown in figure 8-5, the interest coverage ratio, which measures a utility's ability to repay its debt obligations—and is the principal consideration in bond rating decisions, tends to decline for a utility engaged in a major construction project as outlays are made during the construction period. Under the low demand growth scenario in figure 8-5,[19] investment in a series of small modular plants results in a considerably better interest coverage ratio trend, even with a 10 percent capital cost premium (per kilowatt) associated with the smaller plants. The primary reason for the difference in financial performance is the ability of the smaller plant to track demand growth. Under the low demand growth scenario, the interest coverage ratio for the large plant is relatively low both during the construction period of the plant[20] and during the period that the system has high reserve margins. Use of a low-high demand scenario[21] narrows the difference. Indeed, the interest coverage ratio trend for the large plant surpasses the small plant trend after the large plant comes on-line in 1997.

Figure 8-5.—Short v. Long Lead-Time Analysis: Impact on Financial Health



SOURCE: Office of Technology Assessment.

Summary

The new technologies addressed in this assessment have the potential to compete economically with conventional generating technologies, e.g., pulverized coal, combustion turbines. The new technologies which are most likely to provide lower cost power are AFBC, IGCC, geothermal, and wind power. Fuel cells and photovoltaics could compete favorably with peaking technologies such as combustion turbines. Storage technologies could also compete effectively with these peaking technologies. In addition, most of the generating technologies considered in this assessment offer the small-scale modular features many utilities are seeking, although many are subject to significant cost and performance uncertainty.

A more serious impediment to utility investment in these new technologies for the next 10 to 15 years is that most of them are not likely to compete effectively with other generally more cost effective strategic options—life extension and rehabilitation of existing generating facilities, and increased reliance on load management. These strategic options are being aggressively pursued by many utilities. OTA analysis of these options indicates that their implementation could provide

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[18] A scaled-down Northeast EPRI Regional System was used for this analysis. The initial capacity is 6,600 MW and initial peak load is 5,500. The first year of the scenario is 1990 and continues until 2000. A 800 MW coal plant is assumed to start-up in 1992. A pulverized coal plant is the technology examined. The only differences between the two types of plants are:

	Small	*Large*
Capacity	100 MW	500 MW
Lead-time	1 year	7 years

[19] Two percent load growth in the first 5 years and 0 percent in the last 5 years. Edison Electric Institute, *Strategic Implications of Alternative Electric Generating Technologies* (Washington, DC: EEI, April 1984).

[20] The 500 MW plant is assumed to come on-line in 1997.

[21] Two percent load growth in the first 5 years and 6 percent in the last 5 years.

sizable benefits to utilities and enhance utility financial health. As a result, the new technologies may take longer to achieve the low costs projected in this section.

NONUTILITY INVESTMENT IN POWER GENERATION

Overview

Interest in nonutility electric power generation has increased in recent years. In some parts of the country, California being the most notable example, nonutility generation has emerged both as a significant source of power and as a strategic option for utilities. In addition to existing industrial self-generation, power is now being sold by companies operating low-head hydroelectric dams, cogeneration, wind turbines, geothermal powerplants, and, to a much more limited extent, photovoltaic arrays and solar thermal electric facilities.

Nonutility generating facilities are owned by industrial and commercial firms, and third-party entrepreneurs. This increase in activity is due, primarily, to a supportive regulatory climate and the availability of tax benefits. And whether a healthy nonutility power generation industry emerges in the 1990s will depend on policy decisions over the next few years. This section examines:

1. characteristics of current nonutility producers,
2. nonutility technology choice decisionmaking,
3. the comparative profitability of these technologies, and
4. the impact of Federal tax policy.

Historical Nonutility Generation

Industry has generated electricity since the earliest days of electric power. This power generation included both onsite production to meet industrial needs and cogeneration. The contribution of this industrial capacity to overall electricity production has declined over time, however. In 1962, capacity at nonutility owned generating plants represented 8.5 percent of total installed generating capacity. By 1979, this contribution, while remaining relatively constant in absolute terms, had slipped to 2.8 percent of total generating capacity.[22] In the 1970s, industrial self-generation (including cogeneration) of electricity decreased in the face of increasing fossil fuel prices, aging plant, a flattening of demand, and a generally lower rate of increase in the price of purchased electricity.[23] Changes in this trend, however, may be emerging in the 1980s—the real price of oil has stabilized, curtailments of natural gas no longer occur, the retail price of utility power has continued to increase, and regulatory changes that make it economically attractive to produce electric power for sale to utilities.

Current Nonutility Electric Power Generation

With the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), the prospects for generation of power outside of electric utility ownership improved markedly. Prior to PURPA, owners of nonutility powerplants did not have guaranteed markets for their power beyond their own use, and were subject to possible public utility regulation. Rates for sales of power to utilities were open to negotiation without a consistent "yardstick" against which negotiated rates could be measured. PURPA changed this situation by providing a 100 percent "avoided cost criterion" for these rates and removing potential for regulation. Chapter 3 discusses PURPA in more detail.

The nonutility market for sale of power has increased significantly since the early 1980s. Installed nonutility generating capacity in 1985 consists primarily of cogeneration applications (mostly from natural gas), biomass-fired generation, wind, geothermal, AFBC, and hydro. Additional activity is occurring in solar thermal electric and photovoltaics. Table 4-4 shows the installed capacity breakdown for the new technologies in 1985. Wind power and AFBC are the subject of the most activity.

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[22] Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry/1982* (Washington, DC: EEI, 1983).

[23] R.C. Marlay, "Trends in Industrial Use of Energy," *Science*, vol. 226, No. 4680, Dec. 14, 1984, pp. 1277-1283. These numbers do not include boilers using nonfossil fuels.

Characteristics of Nonutility Producers

Nonutility involvement in new technology development is being initiated by both industrial firms and third-party investors. Industrial investment in new technology projects is primarily undertaken to reduce the cost of meeting electrical and/or process heat needs. Either revenues from power sales to electric utilities or the avoidance of electricity purchases can make a project economic. By contrast, third-party investment in these technologies is organized by entrepreneurs who obtain financing and develop projects as profit-making ventures from sale of the electricity and any byproduct steam. Both types of development have occurred in recent years—with industrial involvement centering on cogeneration and third-party investment principally occurring in cogeneration, low-head hydroelectric dams, and wind power.

In order to gauge the level and type of current nonutility power generation, OTA sponsored a survey[24] conducted by the Investor Responsibility Research Center (IRRC). The trends and characteristics in the IRRC sample provide insight into the nature of the industry and the direction it appears to be headed.

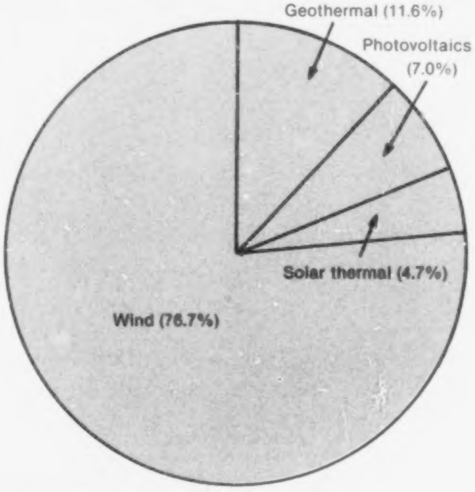
IRRC sent a survey form to current and projected nonutility power producers in the wind, solar thermal electric, geothermal, and photovoltaic industries.[25] It asked questions on the following topics:

- ownership,
- financial structures,
- generating plant characteristics,
- vendor agreements,
- operational data, and
- purchase agreements with utilities

Figure 8-6 shows the breakdown by technology of the survey respondents. Note that wind power companies represented 76.7 percent of the respondents, and geothermal power came in a distant second at 11.6 percent. In terms of total installed capacity, the disparity is even greater. By the end of 1983, the IRRC sample reports that wind power accounted for over 134 MW of capacity.[26]

The survey results reveal two important industry characteristics which could affect industry health and the impact of Federal policy in the mid 1980s. First, most companies involved in nonutility power projects are relatively young—less than 3 years old. Second, these companies are quite small, typically maintaining generating capacity of less than 6 MW. Any significant changes in tax and regulatory policy could severely affect the operations and profitability of these young firms.

Figure 8-6.—Survey Responses by Technology



SOURCE: Office of Technology Assessment.

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[24] Investor Responsibility Research Center, *Survey of Non-Utility Electric Power Producers*, OTA contract 433-7640, July 11, 1984.

[25] A total of 45 companies (25 current and 20 projected producers) responded to the survey. IRRC also surveyed the biomass and hydroelectric small power industries. The remaining technologies highlighted in this report (fuel cells, AFBC, and IGCC) were not sufficiently commercialized or deployed in 1983 to be surveyed.

[26] Comparison of this reported capacity with the 239 MW reported in D. Marier, "Windfarm Update . . . 117 Megawatts and Still Growing," *Alternative Sources of Energy*, No. 63, September/October 1983, suggests that the IRRC sample contains a little over one-half of the industry in 1983.

Figure 8-7 shows the cross-section of **ownership** of current and projected nonutility producers. The majority (78.6 percent) of these producers are privately owned companies, most of which are small in size and were formed strictly to sell power to utilities. Far fewer publicly held companies and subsidiaries, particularly more established, older, and larger firms, have entered the market as yet.

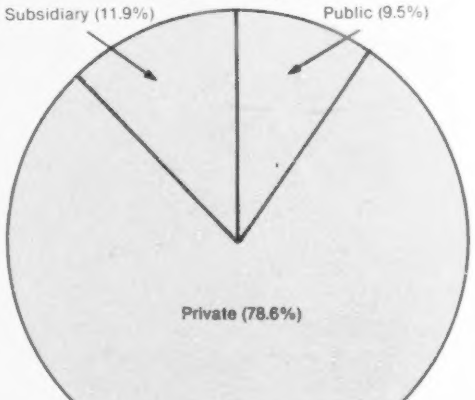
The survey respondents were also asked about the **financing methods** they have used to capitalize and operate their generating facilities. The responses from the currently producing companies fall generally into four major categories: sole ownership, joint ventures, partnerships, and leasing. Partnerships are the most prevalent, accounting for half of the projects surveyed. Sole ownership ranked second—29.4 percent; joint ventures and leases accounted for 14.7 and 5.9 percent, respectively. This cross-section indicates that most of the current projects, i.e., wind farms, are generally financed with private investor capital, although over one-quarter of the respondents noted that they have used a mixture of financing methods such as sole ownership along with partnerships.

The survey indicates that the **project location** of most of the current and anticipated nonutility projects represented in the survey is California (see figure 8-8). California represents an even larger portion of nonutility capacity—over 90 percent of the 1983 reported installed capacity. The primary reasons are the availability of high utility avoided cost rates, tax credits (State and Federal), and California's generally supportive regulatory environment for alternative energy development.

Wind power represents all of the reported 1983 **installed capacity** of 134 MW in the survey. The average wind farm in the survey had an average capacity of 5.8 MW. Figure 8-9 shows that while small companies dominate the market in terms of total projects, in terms of installed capacity larger companies represent a much greater share of the industry.

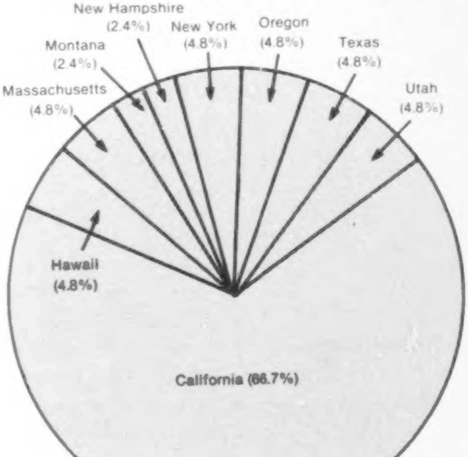
The **year of initial generation** for most companies has been within the last 3 years. Although PURPA and the business renewable tax credits were first passed in 1978, significant nonutility generation did not occur until 1982 because of court challenges to PURPA and slow implementation by States. As mentioned earlier, most of the companies involved in nonutility production are less than 3 years old; over 60 percent of the companies in the survey started producing in 1982 and 1983 (see figure 8-10).

Figure 8-7.—Nonutility Ownership: Current and Projected Companies



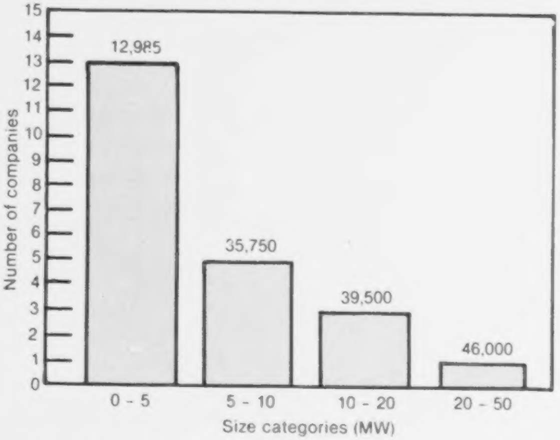
SOURCE: Office of Technology Assessment.

Figure 8-8.—Survey Responses by Project Location



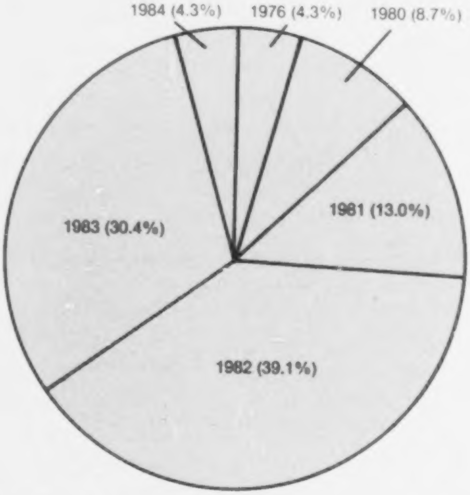
SOURCE: Office of Technology Assessment.

Figure 8-9.—Wind Farm Installed Capacity Distribution (number of companies and total kilowatts)



SOURCE: Office of Technology Assessment.

Figure 8-10.—Initial Year of Generation: Currently Producing Companies



SOURCE: Office of Technology Assessment.

Nonutility Investment Decisionmaking

Investment in power generation equipment in a nonutility environment is generally not very different than other long-term investment decisions. Investors, either individuals or corporations, are primarily interested in maximizing their risk-adjusted return on their invested capital. Hence, investor interest will increase if nonutility power project investments offer potentially high returns relative to other investment options. But the rationale for the investment will vary according to the types of investors. Additional considerations for investors include tax status, timing of the investment, cash flow patterns, and maintenance of a balanced portfolio of risky and nonrisky investments.

Financing Alternative Technology Projects

Investment in nonutility generation projects can be initiated through a variety of financing structures. For a corporation (industrial or commercial), the two major vehicles are capital investment with internal funds, and project financing (sometimes called "third party financing"). Capital investment by a corporation usually involves the use of retained earnings, equity, or debt issues to finance a generation project. Project financing, on the other hand, looks to the cash flow and assets associated with the project as the basis for financing. Private investors often invest in technology projects through tax shelter syndicates and partnerships. Some nonutility power projects have involved both industrial and private investor participation. The following discussion highlights the major forms of nonutility financing mechanisms.

The likelihood of **sole ownership** by a corporation of a nonutility generation project depends on the size and financial strength of the industrial firm, the rationale for investment, and the riskiness of the technology. A large corporation will be more willing and able to finance a project with retained earnings than a small industrial firm. A large firm usually has more retained earnings available for discretionary investment. If a corporation has a stake in the development of a technology, e.g., the corporation is a vendor of the technology, successful ownership of a project such as a photovoltaic array or wind farm may attract future investment by third parties and lead to increased profits for the corporation. A project directly related to a firm's manufacturing process—e.g., providing process steam or electric power directly to an industrial operation—is also more likely to be financed internally. But a project operated strictly as a small power producer is less likely to be owned solely by a corporation. Investments in projects that are more associated with a firm's principal line of business (e.g., sales expenditures or plant expansion) are more likely to receive higher priority. In addition, if the technology under consideration is perceived as risky, an industrial firm may seek partners or guarantees from vendors to share the project risk.

The methods of **project finance** are particularly appropriate to the financing of distributed electricity generation. As mentioned earlier, project financing looks to the cash flow associated with the project as a source of funds with which to repay the loan, and to the assets of the project as collateral. For successful project financing, a project should be structured with as little recourse as possible to the sponsor, yet with sufficient credit support (through guarantees or undertakings of the sponsor or third party) to satisfy lenders. In addition, a market for the energy output—electrical or thermal—must be assured, preferably through contractual agreements; the property financed must be valuable as collateral; the project must be insured; and all government approvals must be available.[27] There are four major forms of project finance applicable to new technology projects: leasing, joint ventures, limited partnership, or small power producer (see box 8C for definitions).

Another ownership structure often used in wind turbine farms is an organized system of individual turbine sales, also known as sole ownership (or "chattel"). Under this structure the private investor owns only one turbine.[28] The project developer organizes the wind farm, sells the wind turbines to prospective investors, and provides maintenance services.

Required Project Characteristics

Every nonutility generation technology project, whether it is structured through traditional project financing techniques or third-party entrepreneurs, must meet several requirements before it will be acceptable to investors. These requirements fall into three key areas: risk reduction, firm fuel and power sales contracts, and sufficiently high profitability (before or after taxes depending on the investor).

There are several forms of risk involved in new electric generation technology projects.[29] They include among others:

1. *Machine Risk:* Will the technology perform as predicted, i.e., produce the estimated power, meet availability targets, and not suffer catastrophic failure, all within appropriate installation and operational budgets?
2. *Resource Risk:* Will the site actually have sufficient fuelstocks (e.g., low-cost coal or geothermal brine) or quality resource (e.g., wind speeds and distribution) for the duration of the project? Will year-to-year fluctuations be great?
3. *Political Risk:* Will the "rules of the game" regarding tax credits and deductions, sales prices to utilities (or others), zoning ordinances, or other permitting regulations change for the worse during the course of operation?
4. *Energy Price Risk:* Will the oil market soften further? Will the utility be allowed to convert to coal or other low-energy cost options?

In order to finance a new nonutility project, these risks must be either mitigated or incorporated in contingency plans. Common risk reduction techniques include vendor guarantees, take-or-pay contracts with utilities, and guarantees on project profitability from the project sponsors. Nevertheless, not all of the risks in projects utilizing new technologies can be eliminated. The higher the level of risk, the higher is the return on investment demanded by investors.

The most critical requirement for nonutility generation projects is the guarantee of stable fuel supply and power sales contracts. Fuel supply, whether it be natural gas, coal, or geothermal brine, must be assured for the duration of the project at reasonable, predictable prices. Even more important than fuel supply contracts are power sales contracts with electric utilities. Without long-term, power sales contracts, project developers will have difficulty obtaining debt and leveraging their investment to reduce capital costs. The guarantee of a sale, at a predetermined price (other acceptable price structures include price floors and schedules of future prices) per kilowatt-hour sold, will allow investors to calculate, with a reasonable degree of certainty, the cash flow associated with a wind turbine installation.[30]

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[27] P.K. Nevitt, *Project Financing* (London: Euromoney Publications Limited, 1979).

[28] R. Ceci, "Investing in Windpower: Ownership or Partnership," *Alternative Sources of Energy*, No. 71, January/February 1985.

[29] M. Lotker, "Making the Most of Federal Tax Laws: A New Way to Look at WECS Development," *Alternative Sources of Energy*, No. 63, September/October 1983, p. 38.

Box 8C.—Project Financing

There are four major forms of project financing used to develop nonutility projects:

- *Leasing*: Lease financing may be appropriate for projects in which the participants: 1) cannot use currently all the tax benefits associated with ownership of the project, 2) can benefit from off balance sheet financing, or 3) wish to utilize a new source of funds—the lease equity market. Through lease financing, participants may transfer ownership of all or a portion of the project to an equity investor or investors who will receive all or a portion of the tax benefits of ownership. By transferring the benefits to an equity investor who can use the benefits currently, the participants are able to reduce significantly their overall cost of financing the project.[1] Two types of lessors may be involved in project financing: sponsors of a project who lease to the project company, and third-party leasing companies that are in the finance business. The third-party lessors may have more attractive rates because they utilize the tax benefits of owning the equipment.
- *Joint Ventures*: Under the joint venture approach, a corporation undertakes the project with one or more partners. The partners may be investor groups whose primary role is to furnish the required capital, other independent firms that furnish either capital or other services (e.g., operation and maintenance), or equipment vendors. A joint venture can be either a separate corporation or a partnership.[2] A major rationale for joint ventures is the pooling of risks among the partners or participants.
- *Small Power Producer*: A third major form of project financing has been used for many recent nonutility projects, particularly wind farms. In this approach a Small Power Producer (SPP) as defined by PURPA (see chapter 3 discussion), which may be an individual, partnership or corporation, owns the generation project but is not the ultimate user of the power. The SPP may sell the electricity produced to the local utility or other users, or may lease the generating equipment itself to a user. The SPP should be able to sell its electricity at high prices and have sufficient tax liability (usually due to income from other sources) to take advantage of the tax credits and deductions.[3] A primary source of capital for these projects are individual private investors, normally in limited partnerships.
- *Limited Partnership*: A limited partnership is an association of one or more general partners who: 1) manage the project, 2) assume the risks, and 3) may make guarantees to limited partners. Limited partners: 1) provide equity funding, 2) may not play an active management role, and 3) assume risk usually limited to the amount invested or a pro rata share of the partnership's debt. A major reason that limited partnerships are attractive ownership options is that tax benefits are distributed to partners who can make most effective use of them.[4] An additional reason is the avoidance of the double taxation of income in corporations (i.e., taxation of corporate income and taxation of dividends). They are widely used in real estate, oil and gas drilling, leased equipment, and other properties.

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[1] Merrill Lynch Capital Markets, *Project Financing* (New York: Merrill Lynch Capital Markets, 1984).

[2] Alliance to Save Energy, *Third-Party Financing: Increasing Investment in Energy-Efficient Industrial Projects* (Washington, DC: U.S. Department of Energy, November 1982), DOE/CS/24448—T1.

[3] M. Lotker, "Making the Most of Federal Tax Laws: A New Way to Look at WECS Development," *Alternative Sources of Energy*, No. 63, September/October 1983, p. 38.

[4] Ibid.

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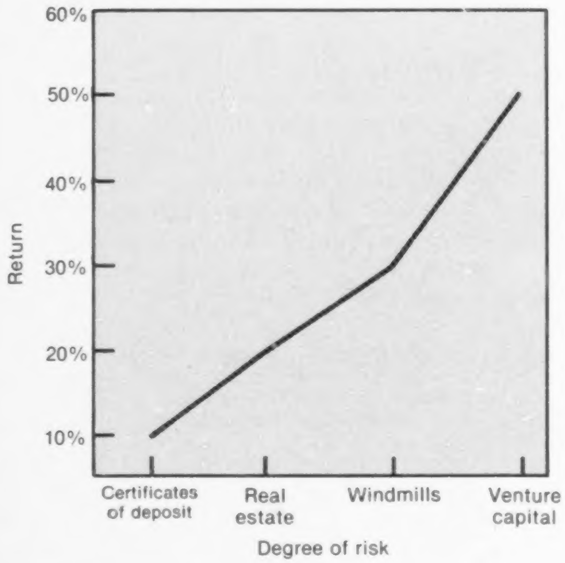
[30] Ibid.

Another requirement for the financing of new technology projects is a sufficiently high rate of return to attract capital. Generally, the nominal internal rate of return (IRR) for a project must be between 20 and 30 percent.[31] For example, as can be seen in figure 8-11, windmills fall between real estate and venture capital on the investment risk continuum. Since the IRR is sensitive to tax and financing, an equally important determinant of profitability is cash return on the capital asset. Cash return on capital assets is obtained by removing tax benefits and debt and concentrating on the straight cash-on-cash return. A minimum required cash-on-cash return of 5 percent after operating expenses is typical.[32] If debt financing is used, the project must show a favorable debt service coverage ratio to obtain debt at reasonable terms. Most suppliers of debt capital require at least a 1.2:1 coverage ratio.[33]

Figure 8-11.—Investment Risk Continuum



SOURCE: American Wind Energy Association, briefing for congressional committee staff, Washington, DC, Jan. 18, 1985.

Comparative Profitability

The primary basis for cross-technology comparisons that follow will be the profitability of new technology projects to both institutional and individual investors. The source for the technology cost and performance estimates are the detailed tables included in appendix 8A to this chapter. Cross-technology comparisons based on projected costs and performance will be presented first, followed by a discussion of the sensitivity to these results to key parameters. Alternative Federal policy scenarios, e.g., tax policy, will also be examined.

The technologies examined in this section will be geothermal power, wind power, solar photovoltaics (concentrators[34]), solar thermal electric, fuel cells, and atmospheric fluidized-bed combustion (AFBC). (Integrated coal gasification/combined-cycle (IGCC) plants addressed elsewhere in this assessment will not be included in this analysis because the technology is currently geared toward the utility market, and cogeneration-sized IGCC plants are not expected to be deployed in the 1990s.) All the technologies listed above are assumed to produce just electricity, except fuel cells and AFBC for which cogeneration applications are examined. Neither of these latter two technologies currently qualify as small-power producers under PURPA, and, hence, were configured as cogenerators for the analysis. Combustion turbine-based cogeneration, currently the primary technology used in new cogeneration applications, is used as the conventional alternative against which the new technologies are compared.

Basic Assumptions

Comparisons among technologies will be made primarily by assessing their breakeven cost and performance. Breakeven analysis determines the capital cost and electricity production parameters necessary for a project to cover both costs and required return on investment. A standard discounted cash flow methodology was also used to compare technologies, and check the results of the breakeven analysis. This methodology calculates profitability measures and is based on methods used by the financial community. The discounted cash flow methodology is described fully in appendix 8A.

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[31] This nominal range translates roughly into a real IRR range of 15 to 25 percent if a 5 percent inflation rate is assumed. Thus, 15 percent will be used as the required rate of return or "hurdle" rate in the following analysis.

[32] R.A. Lyons, "Raising Equity: A Broker-Dealer Guide For the Project Developer," *Alternative Sources of Energy*, No. 69, September/October 1984, p. 20.

[33] Edward Blum, Merrill Lynch Capital Markets, personal communication with OTA staff, Aug. 28, 1984.

[34] Tracking concentrator systems were chosen for the base case nonutility comparison because initial results indicated that they will penetrate the grid-connected power generation market first with the highest profit.

In order to compare the different technologies on a consistent basis in both of these methodologies, several assumptions were made. As discussed earlier, the comparisons are made on a constant dollar (1983) basis. This allows the comparison of technologies with different reference years, lead-times, and lifetimes. The technologies were examined for three scenarios: worst case, most likely case, and best case. These scenarios were derived from the parameter ranges in the cost and performance projections developed in chapter 4 and listed in appendix A.

Breakeven Analysis

As discussed in chapter 4, each new technology has a unique set of cost and performance parameters, such as capital cost, capacity factor, and expenses. These parameters can be compared to an assumed revenue stream (from electricity sale to utilities or thermal revenues from cogeneration) and required rate of return to determine technology cost effectiveness. The basic concept is to match initial cost and annual electricity production (measured as the capital cost per annual kilowatt-hour) to the sum of net revenues and tax benefits (see box 8D). If a technology's capital cost per annual kilowatt-hour is lower than revenues and benefits, the technology is cost effective. This comparison is called breakeven analysis and is used in financial analysis to provide a relatively simple quide to the profitability of a project.[35] If a technology appears profitable, more detailed analysis and structuring of the project is undertaken.

Figure 8-12 shows breakeven graphs for three groups of technologies: a) wind power, solar photovoltaics, and AFBC; b) geothermal and solar thermal electric (parabolic dish); and c) fuel cells and combustion turbines. Each group represents a different level of annual expenses.[36] For example, technologies with high fuel expenses, such as fuel cells, have much higher expenses than wind turbines and solar photovoltaics, which have no fuel expenses. The three lines in each graph represent breakeven capital cost per kilowatt-hour as a function of the avoided cost buy-back rate. Each line is associated with a particular set of required real rate of return (10, 15, and 20 percent).[37] Along side each breakeven graph are the capital cost per kilowatt-hour ranges associated with the new technologies. The high end represents the worse case, the low end represents the best case, and the mark in the middle is associated with the most likely case.

This graph can be used in two ways: 1) to determine the breakeven capital cost per kilowatt-hour associated with a specific avoided cost, and 2) to calculate the required avoided cost rate that each technology needs in order to break even. The top graph in figure 8-12 provides an example of the first type of analysis. The dotted lines trace an avoided cost buy-back rate of 5 cents/kWh[38] and a 15 percent required real rate of return. As can be seen in this figure, wind power could be profitable at this buy-back rate if capacity factors can be increased and initial capital cost can be reduced. While wind power could be cost effective under these conditions, at costs and/or capacity factors associated with the upper portion of wind's capital cost per kilowatt-hour range, profitability will likely be marginal. These graphs also indicate that AFBC, geothermal, and combustion turbines are economic at a wide range of buy-back rates. Conversely, solar thermal, and to a lesser extent, photovoltaics and fuel cells require significantly higher buy-back rates. Both photovoltaics and fuel cells become more economic in the lower portions of their cost ranges.

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[35] Edward Blum, Merrill Lynch Capital Markets, personal communication with OTA staff, Mar. 19, 1985.

[36] The expense groups were derived by grouping the technologies according to the percentage of total lifecycle revenue accounted for by the sum of operating, fuel, insurance, and land rental costs. These percentages were estimated with the discounted cash flow model discussed in this section. The percentages are 20 percent for wind, photovoltaics, and AFBC; 25 percent for solar thermal electric and geothermal; and 60 percent for fuel cells and combustion turbines.

[37] The base set of assumptions are 10 percent Investment Tax Credit (no Renewable Tax Credit), 5 year ACRS depreciation, 50 percent Federal tax rate, 100 percent equity financing, and 2 percent real fuel escalation. The fuel escalation rate serves as the proxy for the rate of increase in avoided cost rates.

[38] This buy-back rate was chosen because it approximates avoided costs for Pacific Gas & Electric and Southern California Edison in 1984.

Box 8D.—Breakeven Analysis

Breakeven analysis, as implemented in this report, is used to determine which parameters equate a project's costs with its revenues and benefits. The focus in this chapter is on which avoided cost buy-back rate is necessary for a new technology project to breakeven.

The equations used to conduct the breakeven analysis are based on the equating capital cost with revenues and tax benefits over the life of the project. This principal can be expressed for a project financed with 100 percent equity as:

$$C = (1 - T)K(1 - E)pR + (TC + f)C$$

where:

C = Capital cost in \$/kWh
T = Federal tax rate (percent)
K = Annual production in hours
E = Expenses as a proportion of total revenue
p = Present value of an escalating series, i.e., $p = \sum_{i=0}^{N} (1+e)^i/(1+d)^i$
e = Real fuel escalation rate (percent)
d = Discount rate (required rate of return) (percent)
N = Project life
R = Initial buy-back rate in cents/kWh
TC = Federal tax credit (combination of investment tax credit and any energy tax credits) (percent)
f = After tax present value of accelerated depreciation (percent).

The first part of the right side of the equation corresponds to revenue and the second part refers to tax benefits.

A useful measure of the cost of a project is capital cost per annual kilowatt-hour. Capital cost per annual kilowatt-hour is calculated by dividing capital cost by the capacity factor times 8760 hours. Figure 8A-1 performs this calculation for a variety of capacity factors. The above equation can be transformed to equate project revenue and tax benefits per kilowatt-hour to capital cost per annual kilowatt-hour:

$$C/K = \frac{1 - T)(1 - E)pR}{1 - TC - f}$$

Representative values for each of the equation's parameters can be used to estimate the breakeven capital cost per annual kilowatt-hour. Comparison of this breakeven value to a technology's capital cost per annual kilowatt-hour determines the cost effectiveness of a project. This analysis is shown in figure 8-12.

Similarly, a breakeven buy-back rate can be derived by transforming the basic equation to:

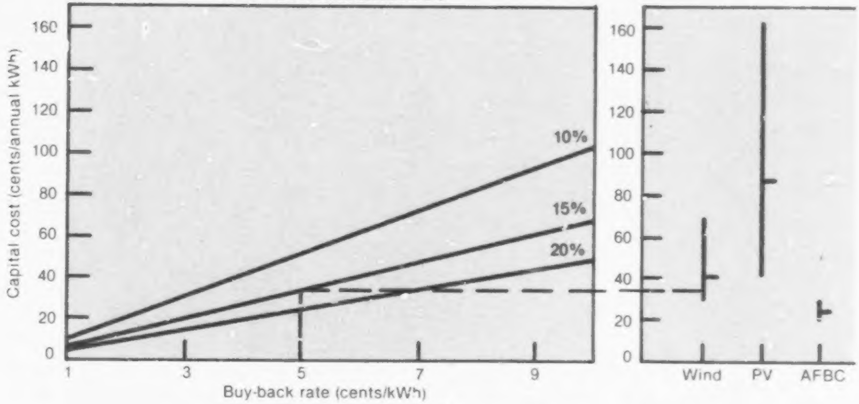
$$R = \frac{C \times (1 - TC - f)}{(1-T)K(1-E)p.}$$

This analysis is performed in figure 8-12.

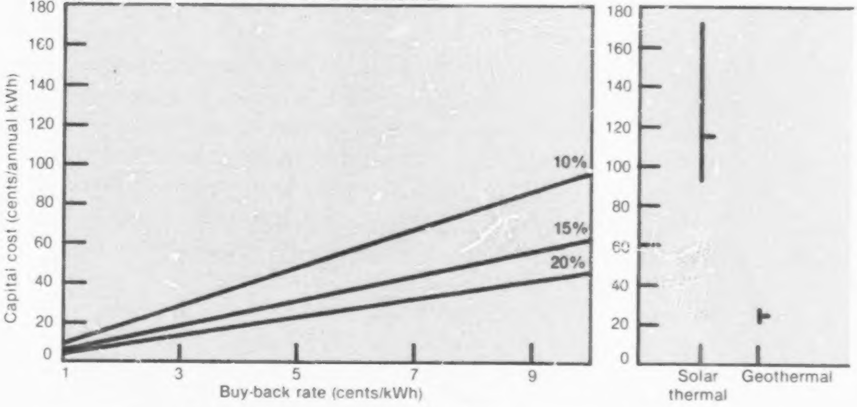
The second analysis approach, calculation of the required avoided cost revenue rate, provides a good basis for comparison of cost effectiveness across the technologies. In addition, the analysis can determine whether a new technology project will be economic with a particular utility or statewide buy-back rate. Figure 8-13 shows the results of this analysis with a 15 percent real required rate of return (or approximately 20 percent nominal) and no Renewable Tax Credit. These results mirror the results listed above. AFBC, geothermal, and combustion turbines are clearly economic throughout their cost ranges at buy-back rates above 4 cents/kWh. At its expected cost and performance levels, wind could be profitable at buy-back rates above 6 cents/kWh. If wind power achieves its most optimistic capital cost and capacity factor ranges, wind

Figure 8-12.—Breakeven Analysis

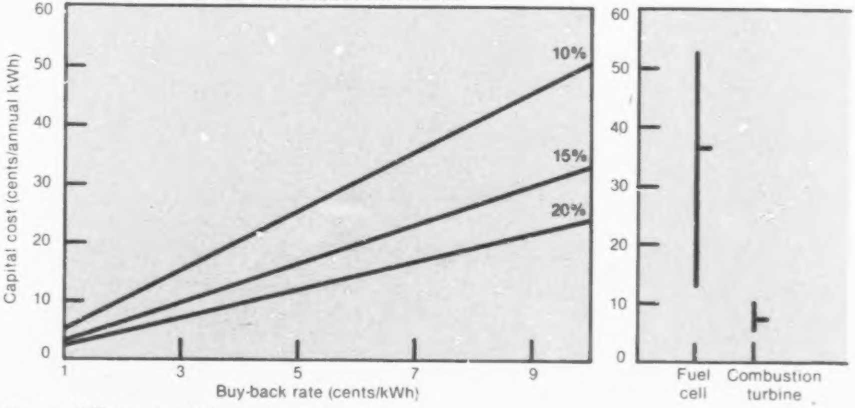
A. Wind-Photovoltaics-AFBC[a]



B. Solar Thermal-Geothermal[b]



C. Fuel Cells-Combustion Turbines[c]

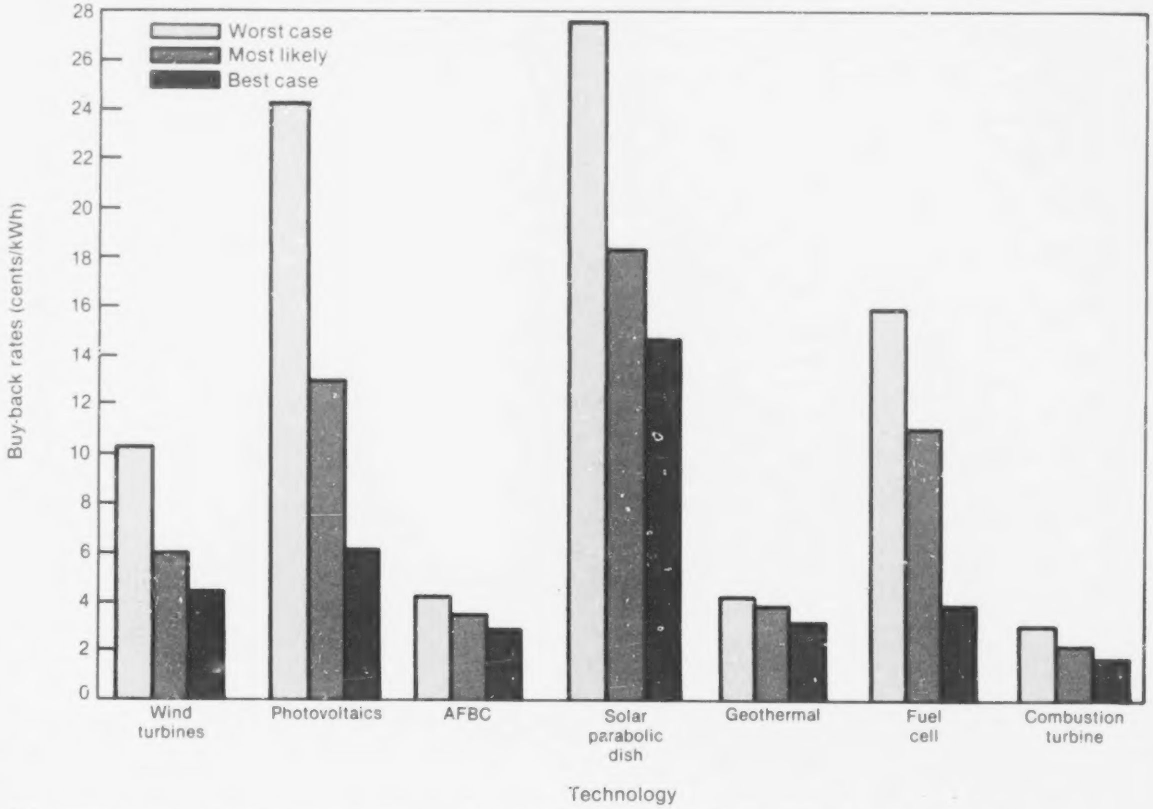


[a] Assumes that expenses equal 20 percent of total revenue.
[b] Assumes that expenses equal 25 percent o total revenue.
[c] Assumes that expenses equal 60 percent of total revenue.

NOTE: All of the graphs assume 2% real fuel escalation, 10% Investment Tax Credit, 5-year ACRS depreciation, and a 50% tax bracket. The three lines in each graph are associated with real rate of return.

SOURCE: Office of Technology Assessment.

Figure 8-13.—Breakeven Buy-Back Rates



NOTE: Assumes 2% real fuel escalation, 10% Investment Tax Credit, 5-year ACRS depreciation, a 50% tax bracket, and 15% real rate of return.
SOURCE: Office of Technology Assessment.

could require only a 4 cents/kWh rate. The breakeven buy-back rate for solar photovoltaics and fuel cells drops below 10 cents/kWh only at their most optimistic cost and performance values. For solar thermal electric, the breakeven rate is above 10 cents/kWh throughout its cost and performance range.

Rate of Return Analysis

In addition to breakeven analysis, a standard discounted cash flow methodology was used to derive profitability, i.e., real internal rate of return. Internal rate of return (IRR) can easily be compared to rates realized by investors, although its calculation and interpretation are not without problems. The most serious problem is the sensitivity of IRR to changes in the debt structure, and other financial parameters (e.g., repayment schedules, leasing, etc.).[39] Since no attempt was made by OTA to structure the financing of a given new technology project in order to gain the best rate of return—the basic cross-technology cash flow model assumes established debt and equity portions for the project, no leasing, and a set Federal tax rate[40]—the calculated rates of return in this analysis will be different from and typically below the rates of return actually achievable.

The results of the comparative profitability analysis are included in figure 8-14. Also listed in are the base case assumptions regarding tax rates,

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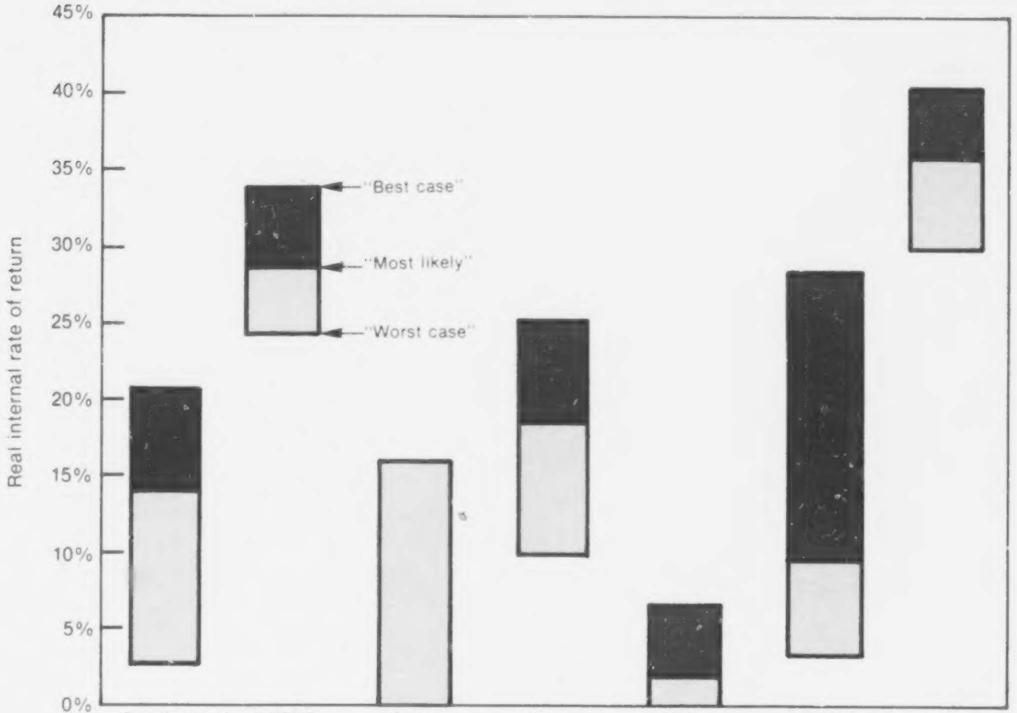
[39] Indeed, many analysts place more weight on payback periods and net present value.

[40] For the basic comparisons, the tax rate is set at the average Federal tax percentage.

Figure 8-14.—Technology Profitability Range: Nonutility Ownership—West



	Geothermal	AFBC[a]	Photovoltaics	Wind	Solar parabolic dish	Fuel cell[a]	Combustion turbine[a]
Size (MWe)	50	40	10	20	10	11	25
Capital cost ($/kW)[b] .	1450	1420	2633	1050	1750	2240	350
Capacity factor	70%	70%	33%	30%	25%	70%	55%
IRR[c]	13.9%	28.6%	0%	18.6%	1.8%	9.5%	35.8%

NOTE: **Basic economic assumptions**—discount rate: 10% (real); debt interest rate: 5% (real); base year dollars: 1983; Federal tax rate: 50%; Federal depreciation: 5-year ACRS; Federal Renewable Tax Credit: 0%; State tax rate: 9.6%; State Renewable Tax Credit: 25%; insurance rate: 0.25% of capital cost; property tax rate: 2.3% of capital cost; Investment Tax Credit: 10%; debt portion: 40%; gas price escalation: 2% per year; oil price escalation: 2% per year; coal price escalation: 1% per year; avoided capacity credit: $70/kW; capacity credit escalation: 2% per year; avoided energy credit: 5.2 cents/kWh; energy credit escalation: 2% per year.

[a] Cogeneration application.

[b] Represents instantaneous capital cost in 1983 dollars.

[c] Real internal rate of return under most likely cost and performance scenario.

SOURCE: Office of Technology Assessment.

etc. Generally, the values listed, especially State taxes and avoided cost rates, represent conditions in California. (California was chosen because the State's current regulatory environment supports nonutility investment, a large portion of existing nonutility new technology activity is occurring in California, and many new nonutility projects in the near future are expected to be developed in the State.) The regional fuel prices were derived from utility-reported data compiled by the Energy Information Administration.[41] The regional aspects of fuel prices are covered in chapter 7. Comparison of the worst and best case scenarios provides a range of profitability; the most likely case results represent OTA's best estimates of future profitability. In general, these results substantiate the relative rankings derived in the breakeven analysis.

This figure shows the attractiveness of AFBC-based cogeneration. Throughout its expected rate of return range, AFBC is clearly the most profitable new technology. These profitability ranges also show the potential for solar photovoltaics and fuel cells to achieve high rates of return[42] under the best case scenario. The capacity contribution and deployment of these "clean" technologies could be sizable if capital costs are reduced and reliability increased for these two technologies. On the other hand, if they do not occur, these technologies do not compare as favorably with the other technologies and may not be deployed in significant numbers.

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[41] These data were compiled by EIA for OTA on Nov. 27, 1984.

Wind power is currently the major source of nonutility generation, other than cogeneration. The results shown in figure 8-12 seem to explain this market dominance—wind power compares favorably with the other technologies. Geothermal power is also expected to achieve favorable rates of return.

Sensitivity to Uncertainty

The nonutility profitability values listed above and shown in figure 8-14 were subjected to the same sensitivity analysis framework that was conducted on utility levelized costs presented earlier. The primary purpose of this sensitivity analysis is to examine the cause of the wide rate of return ranges shown in figure 8-14 for each technology.

In general, the results of sensitivity analyses of the key factors—capital cost, O&M cost, capacity factor, heat rates, and electric-thermal ratio[43]—affecting the profitability of the technologies indicate that the most critical are: capital cost, capacity factor, and heat rate. If the nonutility project cogenerates, then the electric-thermal ratio becomes very important. The relative importance of each of these parameters varies according to duty cycle, relative heat rate, and capital intensiveness.

General economic conditions and Federal policies can also significantly affect the profitability of nonutility projects. The sensitivity of these economic factors—avoided costs, fuel costs, fuel cost escalations, tax credits, Federal tax rate, debt portion, and debt interest rate—were subjected to sensitivity analysis. The most critical factor was the avoided energy cost rate. This is not surprising since the energy credit is the major source of revenue for nonutility technology projects. Next in importance are the Federal tax credit (both investment and energy credits), the Federal tax rate, and avoided capacity credits. As was indicated by the relatively high sensitivity to heat rates, relative fuel costs are also important for fuel-intensive technologies such as combustion turbines. Sensitivity to tax credits is examined further below.

These results highlight three main factors that affect the development of new generation technologies. First, policies geared toward increasing reliability and availability, lowering initial capital costs, and increasing efficiency (e.g., heat rate) will have the greatest impact on the future market potential in the nonutility sector. Second, locating a project in a region or State with high avoided costs is crucial to project profitability. Finally, Federal tax policy can significantly affect changes in the profitability of nonutility projects.

Sensitivity to Federal Tax Policy

The existence of Federal tax benefits for renewable energy projects has been instrumental in the development of the current nonutility industry. Both the nonutility IRRC survey and the previous sensitivity analysis results emphasize the importance of Federal tax credits. Not too surprisingly, the respondents to the IRRC survey advocated their continued existence.[44]

Federal tax treatment of nonutility investment is currently in flux. The current business energy credits are due to expire on December 31, 1985. Failure to extend these credits will markedly reduce project profitability and probably cause an industry shake-out. In addition, the Treasury Department has proposed a massive "tax simplification." This proposal, among other things, would, if enacted, repeal the 10 percent Investment Tax Credit.

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[42] A "favorable" or "sufficiently high" rate of return is assumed to be above a 15 percent real (20 percent nominal) "hurdle rate."

[43] The electric-thermal ratio measures the relative production of electricity and steam from a cogeneration unit. A high ratio indicates that the unit produces relatively more electrical energy than thermal energy.

[44] The IRRC survey was discussed in greater detail earlier in this section.

These tax policies were analyzed with the OTA cash flow model. Cross-technology profitability was calculated for five tax policy alternatives:

1. *No Tax Incentives*—No tax credits, and 15 year SOYD[45] depreciation
2. *ACRS Depreciation*—No tax credits, 5-year ACRS depreciation
3. *Investment Tax Credit*—Same as (2), with 10 percent ITC
4. *10 percent Renewable Tax Credit*—Same as (3), with 10 percent RTC
5. *15 percent Renewable Tax Credit*—Same as (3), with 15 percent RTC.

Case 5 represents current policy. Table 8-1 presents the results of this analysis. Figure 8-15 graphically shows the change in profitability (cumulative) upon stepping through the five cases. As can be seen, profitability changes dramatically among the five policy cases. Under the most likely case scenario, if a 15 percent real rate of return (20 percent nominal) is assumed to be the hurdle rate, AFBC and combustion turbine units are likely to be economic under the No Tax Incentive case. Inclusion of a 5-year ACRS allows wind power to become barely profitable. The Renewable Tax Credits cause a dramatic increase in profitability. For example, wind power achieves a real rate of return in excess of 25 percent with a 15 percent tax credit. Geothermal power also is economic with its 10 percent Renewable Tax Credit. The other new renewable technologies—photovoltaics and solar thermal—also benefit from the Renewable Tax Credits, but remain the technologies with the lowest IRR.

Summary

Generation of electric power by nonutility entities has become an important alternative to electric utility power generation. The existence of a wide variety of markets and interested investors outside electric utilities increases the likelihood that many of the new technologies considered in this study will be deployed. OTA analysis of technology profitability indicates that wind power and AFBC-based cogeneration compete favorably with conventional technology—combustion turbines—under expected conditions. Because of current and expected profitability, the commercialization of wind power technology has gone forward. And investor interest in AFBC should speed its commercialization as well.

Our analysis shows that the renewable energy tax credit coupled with recovery of full utility avoided costs by nonutility power producers have been crucial in both the initial commercial development and the deployment of the new generating technologies. Should avoided cost rates be low or uncertain, their development and application will be retarded. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins, might substantially accelerate their deployment. In addition, without continued favorable tax treatment, development of much of the domestic renewable power technology industry will probably be delayed significantly. In particular, without existing tax incentives, many of the small firms involved in development projects will lose access to existing sources of capital. Even large, adequately capitalized firms may lose their distribution networks, leaving the industry struggling to survive.

CROSS-TECHNOLOGY COMPARISON

Overview

This section overviews the critical cross-technology issues involved in the deployment of the technologies covered in this assessment. The emphasis in here will be on the nonquantifiable characteristics of the technologies, i.e., those that cannot be addressed in a cost or profitability analysis. The primary issues covered in this section will be the environmental impacts and the ease of deploying the technologies. Much of the comparisons in this section are based on information contained in chapters 4, 5, 6, and 7, along with previous sections in this chapter.

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[45] Sum of Years Digits.

Table 8-2.—Alternative Tax Incentives: Cumulative Effect on Real Internal Rate of Return

	Real internal rate of return (percent)						
Tax incentive	Geothermal	Photo-voltaics	Wind turbines	Solar thermal	Fuel cells	Combustion turbine	Atmospheric fluidized-bed
"Worst case" cost and performance:							
No tax incentives[a]	0.1%	0.0%	4.1%	0.0%	0.0%	22.3%	16.9%
Current tax incentives[b]	4.9	0.0	19.1	0.0	3.4	30.0	24.3
Investment Tax Credit (10%)[c]	2.7	0.0	9.9	0.0	3.4	30.0	24.3
Production Tax Credit:[d]							
$0.01/kWh	6.3	0.0	14.9	0.0	7.7	39.1	29.8
$0.02/kWh	6.7	0.0	16.8	0.1	8.6	40.5	31.7
$0.03/kWh	6.8	0.0	17.9	0.1	9.1	40.5	32.6
$0.05/kWh	7.0	0.0	19.0	0.2	9.5	40.5	33.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	2.8	0.0	11.6	0.0	3.6	32.0	24.6
10% with 5 year ACRS	4.9	0.0	15.5	0.0	6.6	36.1	29.6
15% without 5 year ACRS	3.8	0.0	14.5	0.0	5.1	35.3	27.3
15% with 5 year ACRS	6.3	0.0	19.1	0.0	8.9	39.7	32.9
ACRS depreciation:[f]							
5 years	1.2	0.0	5.9	0.0	1.3	25.2	20.2
10 years	1.1	0.0	5.1	0.0	1.2	23.2	18.6
"Most likely" cost and performance:							
No tax incentives[a]	8.9%	0.0%	11.7%	0.0%	5.0%	27.2%	20.4%
Current tax incentives[b]	17.8	8.4	28.4	9.5	9.5	35.8	28.6
Investment Tax Credit (10%)[c]	13.9	0.0	18.9	1.8	9.5	35.8	28.6
Production Tax Credit:[d]							
$0.01/kWh	19.2	5.2	24.6	6.1	14.1	46.2	34.9
$0.02/kWh	20.4	6.7	26.8	7.5	15.3	47.0	37.0
$0.03/kWh	20.8	7.5	27.8	8.2	15.9	47.0	37.9
$0.05/kWh	21.2	8.4	28.8	9.1	16.3	47.0	38.8
Renewable Tax Credit:[e]							
10% without 5 year ACRS	13.9	1.5	19.7	2.1	9.5	38.1	29.1
10% with 5 year ACRS	17.8	4.3	24.7	6.2	13.3	42.3	34.4
15% without 5 year ACRS	15.8	4.3	22.7	4.0	11.3	41.7	32.2
15% with 5 year ACRS	20.4	8.4	28.4	9.5	15.8	46.2	37.9
ACRS depreciation:[f]							
5 years	11.2	0.0	14.7	0.0	7.0	30.5	24.1
10 years	10.3	0.0	13.2	0.0	6.4	28.2	22.3
"Best case" cost and performance:							
No tax incentives[a]	14.2%	9.4%	16.6%	1.7%	20.3%	31.5%	24.8
Current tax incentives[b]	25.5	24.8	35.5	14.4	28.4	40.7	33.9
Investment Tax Credit (10%)[c]	20.7	16.0	25.2	6.6	28.4	40.7	33.9
Production Tax Credit:[d]							
$0.01/kWh	27.0	20.6	31.9	10.2	36.4	52.5	41.0
$0.02/kWh	28.4	22.6	34.2	11.8	38.1	52.5	43.2
$0.03/kWh	29.1	23.7	35.2	12.7	38.6	52.5	44.3
$0.05/kWh	29.4	24.7	36.4	13.8	38.6	52.5	44.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	20.8	16.0	25.6	6.7	28.9	43.3	34.7
10% with 5 year ACRS	25.5	21.3	31.6	11.2	34.2	47.6	40.2
15% without 5 year ACRS	23.3	18.7	28.9	8.7	32.0	47.1	38.1
15% with 5 year ACRS	28.6	24.8	35.5	14.4	37.7	51.6	43.9
ACRS depreciation:[f]							
5 years	17.1	12.3	20.5	3.7	24.0	35.0	28.9
10 years	15.8	11.1	18.6	3.3	22.1	32.4	26.7

[a] Includes Sum of Years Digits depreciation, no Investment Tax Credit (ITC), and no Renewable Tax Credit (RTC).

[b] Includes 5 year ACRS depreciation, 10% ITC, and RTC where applicable.

[c] Includes 5 year ACRS and 10% ITC.

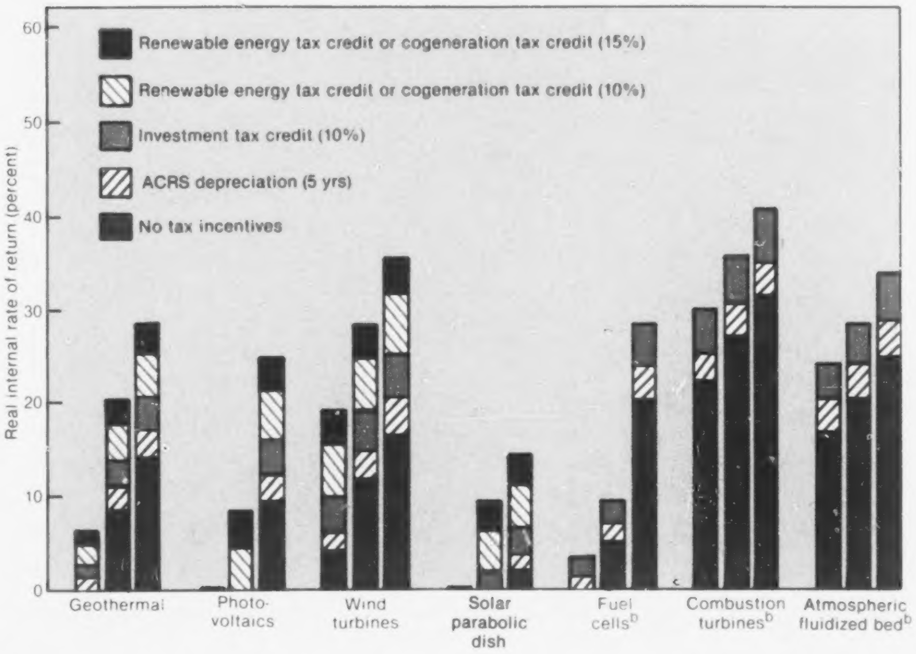
[d] The Production Tax Credit (PTC) is calculated by applying the cents/kWh credit amount to expected yearly electricity production. The credit is applied annually until the cumulative tax credit equals the total tax credit level available with the 15% RTC. The 10% ITC and the 5 year ACRS schedule are also used in computing the PTC.

[e] Includes 10% ITC.

[f] Does not include 10% ITC.

SOURCE: Office of Technology Assessment.

Figure 8-15.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return[a]



[a] Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.
[b] In cogeneration applications.

SOURCE: Office of Technology Assessment, U.S. Congress.

Cross-Technology Issues

The previous sections in this chapter focused on the relative costs and profitability of the developing technologies. Usually, most utilities and investors place the greatest emphasis on these monetary values when making investment decisions. Nevertheless, a host of additional issues can affect and, in some cases, determine the choice of electric power technology. These issues include environmental impacts, fuel availability, and modularity, among others. Table 8-3 displays a variety of quantitative and nonquantitative characteristics of the technologies under consideration.

The most striking aspect of this table is the wide variation in the cost, performance, resource, and environmental attributes evidenced by the different technologies. The new technologies vary from small, short lead-time technologies such as wind power to large, longer lead-time technologies such as IGCC; from capital-intensive, less mature technologies like fuel cells to low cost per unit power, commercial technologies such as geothermal; and from site-specific technologies such as geothermal to more easily sited technologies such as photovoltaics. This variation among the technologies makes easy classification of the technologies difficult. Trade-offs between important characteristics such as cost, environmental impacts, and lead-time must be made prior to selection of a particular technology. Nevertheless, a few insights concerning these cross-technology issues can be made.

First, although the clean coal technologies, i.e., AFBC and IGCC, are low in cost per unit power, and can use a variety of fuels and fuel types, the potential environmental impacts from these technologies are significant. AFBCs and IGCCs require sizable quantities of water and land, produce sig-

Table 8-3.—Cross-Technology Comparison: OTA Reference Systems

Technology characteristics	Geothermal	Wind power	Photovoltaics	Solar parabolic dish[a]	AFBC	IGCC	Fuel cells	CAES	Battery storage
General:									
Geographic location	Western U.S.	Entire U.S.	Entire U.S., South better	SW & SE	Entire U.S.	Entire U.S.	Entire U.S.	Entire U.S.	Entire U.S.
Plant size[b]	Small-medium	Small	Small	Small	Large	Large	Small	Medium-large	Small
Development status	Demo-commercial	Commercial	Demo-commercial	Demo	Commercial under construction	Demo	Demo planned	No Demo	Pilot
Lead time[c]	Short-medium	Short	Medium	Medium	Long	Long	Medium	Medium-long	Medium
Siting flexibility[d]	Low	Medium	High	Medium	Medium	Medium	High	Medium	High
Intermittent?[e]	No	Yes	Yes	Yes	No	No	No	No	No
Cost:									
Cost[f]	Medium	Medium	High	High	Low	Low	High	Medium	Low
Profitable?[g]	No	Yes	No	No	Yes	N/A	No	N/A	N/A
Resource requirements and environmental impacts:[h]									
Primary fuel source	Geothermal brine	Wind	Solar insolation	Solar insolation	Coal/solid fuels	Coal/natural gas	Natural gas	Base load electricity plus natural gas or oil	Base load electricity
Fuel availability	Limited	Limited number of quality sites	Region specific	Region specific	Not constrained	Not constrained	Not constrained	Not constrained	Not constrained
Noise	Medium	Medium to high	Low	Low	Medium	Medium	Low	Medium	Low
Solid waste[i]	Medium	Low	Low	Low	Medium to high	Medium to high	Low	Low	Low
Air quality	Medium to high	Low	Low	Low	Medium to high	Medium to high	Low	Medium	Low
Water quality[j]	Medium	Low to medium[k]	Low	Low	Medium	Medium	Low	Low	Low
Water consumption:[l]									
Daily amount[m]	Low to high	Low	Low	Low	Medium	Medium to high	Low	Low	Low
Amount per MWe(net)[n]	High	Low	Low	Low	Medium	Medium	Low	Low	Low
Land use:									
Aereal extent[o]	Low	High	High	High	Medium	Medium	Low	Low	Low
Power density[p]	Medium to high	Low	Low	Low	Medium	Medium	High	High	High

[a] Engine-mounted solar parabolic dish.

[b] Sizes of OTA reference systems: Small = <25 MW, Medium = 25 to 100 MW, Large = >100 MW. For size ranges expected in the 1990s, see table 4-2 (Alternative Generating Technologies and Storage Technologies: Typical Sizes and Applications).

[c] Short = <2 years; Medium = 2 to 5 years; Long = >5 years.

[d] Refers to the general ease of siting a powerplant. Ranking is based on combination of geographical location, fuel availability, and environmental characteristics. Low = plant can be sited only at specific locations, Medium = plant can be sited at many locations, but is constrained by local resource availability, etc., High = plant can be sited at most sites with relative ease.

[e] Refers to the overall reliability of the powerplant, primarily daily resource variability.

[f] Levelized cost (1983$) under most likely case scenario. Low = <7 cents/kWh; Medium = 7-14 cents/kWh; High = > 14 cents/kWh.

[g] Whether technology can achieve a real rate of return over 15 percent in nonutility applications under most likely case scenario. Assumes no Federal Renewable Tax Credit.

[h] These potential environmental impacts are based on the reference plant sizes listed above and focus on direct impacts from onsite operation. Impacts associated with production of facility components, or disposal of worn components, are not considered.

Unless otherwide noted, the following rating system applies:

- High indicates substantial likelihood of large impacts requiring special measures to bring the facility into compliance with local, State, or Federal environmental protection statutes. "High" is also used to identify a strong potential for conflicting land use objectives and problems resulting from competition for scarce resources (e.g., for water in irrigation-dependent areas). In all of these cases, the resulting impacts could be serious enough to constrain full development of a site-specific energy resource.

  Where air emissions are concerned, a high rating may be more reflective of local air quality conditions than actual emission rates. For example, location in a nonattainment area can affect development of any combustion unit large enough to fall under Federal standards.
- Medium indicates that some special measures may be requred to bring the facility into compliance with environmental protection statutes, but these conditions are not likely to seriously limit development.
- Low means that environmental impacts are expected to be negligible.
- Combination ratings (i.e., low-high) indicate that: 1) impacts are likely to vary according to site-specific characteristics, and/or 2) impacts vary substantially with plant size.

[i] From daily plant operation *only*. Wastes associated with production and/or periodic replacement of plant components are not considered.

[j] This includes any effluent discharge to surface water (e.g., lakes and streams); impacts on groundwater are not considered.

[k] Inadequate erosion control in steep terrain could lead to increased sedimentation in nearby streams.

[l] As explained in the following two footnotes, these ratings reflect the amount of water used rather than the consequent environmental impacts of water use. In areas with limited water resources and/or heavy competition for existing supplies, technologies with a moderate rating under this category may face siting constraints.

[m] Low = <1 million gallons per day, Medium = 1 to 3 gallons per day; High = >3 million gallons per day.

[n] Low = <3,000 gallons per day per MWe(net), High = 3,000 to 20,000 gallons per day per MWe(net); High = >20,000 gallons per day per MWe(net).

[o] These ratings are based on the land requirements for a 25 MWe(net) plant. They suggest where potential problems may arise regarding visual impacts, competing land uses, or habitat disruption. Low = ≤10 acres; Medium = 11 to 100 acres, High >100 acres. While extensive habitat disruption could occur on a small site (i.e., ≤10 acres), we have assumed that the affected area would be small enough that overall impacts on the resource in question would not be likely to constrain development.

[p] Refers to the amount of power produced per acre: Low = <0.5 MW per acre; Medium = 0.5 to 5 MW per acre; and High = > 5 MW per acre.

SOURCE: Office of Technology Assessment.

nificant amounts of solid waste, and emit air pollutants. The latter, however, can be controlled below competing, solid fuel technologies. These environmental characteristics will likely limit the deployment of these technologies to remote applications outside of urban areas, possibly to nonattainment areas (unless emission offsets are available). While these technologies have greater environmental consequences than the other new technologies, the IGCC and AFBC represent two of the most promising "clean coal" technologies. Therefore, when compared to conventional coal combustion, the IGCC and AFBC offer substantial environmental benefits.

Second, in general, the renewable technologies—geothermal, wind power, solar photovoltaics, and solar thermal electric—have less severe environmental impacts than conventional generation alternatives. This attractive environmental characteristic in combination with the small, modular nature of most of the renewable technologies, should ease siting of these technologies and aid deployment. There are important differences among these technologies, though, in terms of their environmental impacts. Geothermal and, to a lesser extent, wind power create more environment impacts than solar photovoltaics and solar thermal electric. For example, wind power installations are highly visible, noisy, require large amounts of acreage, and can cause erosion problems in environmentally sensitive areas.

Finally, the two technologies which appear to be the most desirable according to the characteristics listed in table 8-3 are fuel cells and solar photovoltaics. These two technologies are small, modular technologies which can be sited in a variety of locations without major environmental impact in relatively short periods of time. Photovoltaic powerplants use a fuel that is inexhaustible (solar insolation), while fuel cells can use a variety of fuel types (natural gas, methanol, synthetic natural gas). In the case of these two technologies, therefore, cost and performance will almost completely determine their market penetration.

Summary

Choice among the new technologies involves more than just comparison of costs or profitability. At the micro level, this decision is based on very detailed analysis of engineering, and cost analyses, site-specific characteristics, and environmental impacts, among others. At the more general level, the approach taken here, the technologies must be compared with each other, both in relation to their quantifiable and their nonquantifiable values.

This section has highlighted the complex issues associated with deployment of the new technologies. Complicated variations exist among the technologies in terms of their cost, lead-time, and environmental impacts. On one hand, AFBC and IGCC are very cost competitive, but their long lead-times and their relatively large impacts on the environment could make AFBC and IGCC hard to site. On the other hand, flexible, relatively benign technologies like fuel cells and photovoltaics are currently too costly to be deployed in large numbers. Actual technology choice will depend on specific utility concerns and circumstances.

CONCLUSIONS

New electricity-generating technologies have the potential of being competitive with traditional technologies, e.g., pulverized coal, combined cycle, combustion turbines, in the 1990s. Several of the new technologies, specifically, small-scale AFBC and wind power, are in later stages of commercialization, and could provide lower cost or more profitable power in the early 1990s. The status and costs of other new technologies such as fuel cells and photovoltaics are uncertain. Although these technologies are potentially competitive, uncertainties surrounding their cost and performance will slow deployment.

A wide variety of cost-effective strategic options are also available to electric utilities. These options include plant betterment and life extension, load management, and interregional power purchases. OTA analysis indicates that these options are extremely competitive with the traditional generating technologies, and are less costly than the new technologies. Consequently, utilities will probably concentrate on these options prior to extensive deployment of the new, developing technologies.

Investment decisions concerning the new technologies will reflect more than just cost comparisons. A variety of nonquantitative characteristics, particularly modularity and the level and type of environmental impact, will influence investment decisions.

APPENDIX 8A: INVESTMENT DECISION CASH FLOW MODELS FOR CROSS-TECHNOLOGY COMPARISONS

Introduction

This appendix describes the analysis methodologies adopted in this assessment for: 1) utility levelized busbar cost calculations, and 2) nonutility profitability measurement. These methodologies are the basis for the cost and profitability estimates provided in chapter 8. The analysis approach in these models is a modified version of the Alternative Generation Technologies model developed by Battelle Columbus Laboratories.[1] The modifications generally allow the model to more accurately calculate electric utility revenue requirements and nonutility profitability measures. The estimates produced by these calculations can be compared with utility-reported costs and nonutility-reported rates of return.

Electric Utility Levelized Busbar Cost

Since electric utilities are regulated, utility shareholders receive a set return on their investment. The revenue necessary to produce this set income, often termed the revenue requirement, includes three major components: capital cost carrying charges, interest charges, and fuel and operating expenses.

Capital Cost Carrying Charges[2]

The charges associated with a capital investment can be split into three basic categories: 1) depreciation, 2) return, and 3) income taxes associated with the investment.

An annual revenue stream is required to recover the initial capital cost of a new electric generation facility. Book depreciation is the mechanism used to generate the funds needed for this carrying charge component. Book depreciation in year i (D_{bi}) is defined as

$$D_{bi} = \frac{I}{n_b} \qquad [1]$$

where I is the total capital cost of the facility (includes Allowance for Funds Used During Construction) and n_b is the book life in years. Accumulated book depreciation in year i (C_{bi}) is the sum of all the previous years' depreciation, i.e.

$$C_{bi} = \sum_{j=1}^{i-1} D_{bj} \qquad [2]$$

The electric utility also earns a return on the invested capital. The return on capital in year i (R_i) can be found by multiplying the required rate of return k by the remaining undepreciated book value of the facility. (The required rate of

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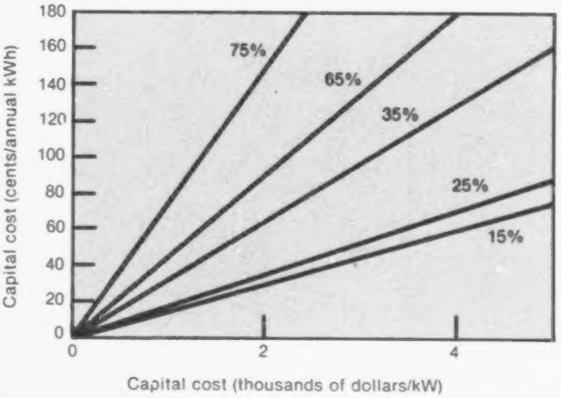
[1] Battelle Columbus Division, *Final Report on Alternative Generation Technologies*, Nov. 18, 1983 (Columbus, OH: Battelle, 1983).

[2] This section draws heavily on Peter D. Blair, Thomas A.V. Cassel, and Robert H. Edelstein, *Geothermal Energy: Investment Decisions and Commercial Development* (New York: John Wiley & Sons, 1982) and Philadelphia Electric Co., *Engineering Economics Course* (Philadelphia, PA: Philadelphia Electric Co., January 1980).

Figure 8A-1.—Calculation of Capital Cost per Kilowatt-Hour[a]



[a]Shown for different capacity factors.

SOURCE: Office of Technology Assessment.

return k is assumed to be equal to the discount rate.):

$$R_i = k[I - C_{bi}] \qquad [3]$$

The third component of capital cost carrying charge is the income tax liability associated with the project. The total tax liability in year i can be determined by multiplying taxable income by the composite tax rate t. The composite tax rate (t) is a weighted combination of the State tax rate (t_s) and Federal tax rate (t_f):

$$t = t_s + t_f(1 - t_s)$$

Total taxable income is found by deducting debt interest (K_i) and tax depreciation (D_{ti}) calculated from the accelerated depreciation schedules,[3] from the revenues received[4]:

$$T_i = t(D_{bi} + R_i + T_i - K_{di} - D_{ti}) \qquad [4]$$

The calculation of tax liability is complicated, however, by the use of accelerated depreciation. The use of accelerated depreciation procedures provides additional depreciation in early years and less in the later part of an equipment's lifetime. Hence, income taxes are lower in the early years and higher in the later years, but the same in absolute total at the end of service life. If these tax depreciation benefits were "flowed-through" directly to customer rates, Equation [4] would an accurate representation of tax treatment. The Economic Recovery Tax Act of 1981 stipulates, however, that tax benefits should be "normalized" over the life of the equipment if accelerated depreciation is used. When normalized accounting is used, the income statement is adjusted to show the taxes that would have been paid if the taxes had been based on straight-line depreciation. This adjustment complicates the calculation of both the return and tax components of carry charges.

To accommodate the tax ramifications of accelerated depreciation accounting, equation [4] can be rewritten as:

$$T_i = (t/1 - t)(R_i - K_{di} + D_{bi} - D_{ti}) \qquad [5]$$

It is often convenient to express debt interest in terms of return on capital, that is, total return (R) can be expressed as:

$$R = \sum_{i=1}^{n_b} R_i = kI \qquad [6]$$

and debt interest can be expressed as:

$$K_{di} = k_d f_d I \qquad [7]$$

where k_d is cost of debt and f_d is the fraction of investment funded by debt. Combining Equations [6] and [7] results in:

$$K_{di} = \frac{k_d f_d R}{k} \qquad [8]$$

Hence equation [5] can be rewritten as:

$$T_i = (t/1 - t)(R_i - (k_d f_d R_i/k) + D_{bi} - D_{ti}) \qquad [9]$$

The use of normalization accounting causes modifications in the return component (equation [3]), principally deferral of income taxes (DT_i):

$$DT_i = t(D_{ti} - D_{bi}) \qquad [10]$$

This convention provides utilities with a source of internally generated funds, i.e., accumulated deferred taxes (CD_i), defined by:

$$CD_i = \sum_{i=1}^{i-1} DT_i \qquad [11]$$

These funds act to reduce the return on the capital portion of the annual total carrying

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[3] The assumed accelerated depreciation schedule is the Accelerated Cost Recovery System (ACRS). The ACRS schedules specify the fractions of initial capital cost that are depreciated each year. For the analysis of the repeal of the ACRS system, accelerated depreciation is calculated by the sum of years digits formula, i.e.:

$$D_{ti} = I \times \frac{(n_t - i + 1)}{n_t(n_t + 1) \div 2}$$

where n_t is tax life. This formula is included in W.D. Marsh, *Economics of Electric Utility Power Generation* (Oxford, U.K.: Clarendon Press, 1980).

[4] If the investment tax credit is used, the Tax Equity and Fiscal Responsibility Act (TEFRA) stipulates that total investment (I) for accelerated depreciation calculation must be reduced by an amount equal to one-half of the investment tax credit.

charges of the facility. Hence, the return component originally expressed in Equation [3] becomes:

$$R_i = k(I - C_{bi} - CD_i) \qquad [12]$$

This return value is used in equation [9] to determine total tax liability. Finally, carrying charges must account for the effects of applicable income tax credits which, for our purposes, assumed to be applied only in the first year. Total carrying charge (CC_i) is then calculated by:

$$CC_i = D_{bi} + R_i + T_i + (ITC \times I) + (ETC \times I) \qquad [13]$$

where ITC and ETC are the investment tax credit and energy tax credit applied, where applicable.

Equations [1], [2], and [9] through [13] are implemented in the modified utility model.

Revenue Requirement

Total revenue requirement (RR_i) is calculated by adding yearly debt interest and operating expenses (O_i), i.e.,

$$RR_i = CC_i + K_{di} + O_i \qquad [14]$$

Operating expenses include fuel, operation and maintenance, consumables, insurance, and property taxes. The yearly level of these expenses is dependent on assumptions concerning initial cost levels and expected escalation.

Standard present value and levelization procedures are used to determine required levelized annual revenues and levelized busbar cost per kilowatt-hour from the yearly RR_i.

Comparison With Other Methods

The resultant busbar cost is directly comparable to busbar costs reported by utilities and regulatory commissions. An alternative technique uses fixed charge rates (FCR) instead of calculating the carrying charge directly. EPRI uses this technique in its Technical Assessment Guide[5] (TAG). The TAG includes tables listing FCRs for different equipment lifetimes, recovery periods, and tax preferences. These FCRs are multiplied by installed capital cost to yield levelized carrying charges. Another source is the finance department of an electric utility, which often computes FCRs for internal planning purposes. While there is no fundamental difference between levelized busbar costs calculated by either method, the methodology presented herein more easily captures significant revenue requirement differences on a year-by-year basis. Moreover, this method is more flexible in handling different equipment lifetimes, ACRS categories, and levels of capital intensiveness associated with alternative technologies.

Nonutility Profitability

Consistent cross-technology financial comparison for nonutility electricity producers is best achieved with profitability measures. Although levelized cost values are perhaps convenient for comparative purposes, the financial community generally uses profitability measures (rate of return, payback period, and net present value) for investment decisionmaking purposes. Measurements of nonutility profitability can be derived in a more straightforward fashion than utility revenue requirement estimation—since nonutility income and taxation calculations are not complicated by tax normalization and regulated return adjustments.

The analysis technique adopted for the project is the standard discounted cash flow methodology accounting for the three major components of nonutility cash flows: revenue, operating costs, and after tax income. The various profitability measures are calculated based on after tax cash flow.

Revenue

The revenue achievable from a new technology project is assumed to be based primarily on prevailing utility avoided cost rates. Avoided cost revenue in year i (AR_i) is based on both avoided energy and avoided capacity credits:

$$AR_i = 8760 AE_i CF I_c + AC_i I_c \qquad [15]$$

where AE_i (\$/kWh) and AC_i (\$/kW) are the avoided energy value and avoided capacity values, respectively, in year i (determined by applying an assumed escalation to the base year value), CF is the capacity factor, and I_c is the installed capacity (in kW). In addition, if the facility is a cogenerator, the thermal output is sold at a price equal to what it would cost to produce the steam in a oil-fired boiler. The thermal revenue in year i (TR_i) is calculated by:

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[5] Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: Electric Power Research Institute, May 1982), EPRI P-2410-SR.

$$TR_i = CP_i + OP_i + FP_i \qquad [16]$$

where

$$CP_i = B_{ci}O_t$$
$$OP_i = O_{ci}O_t$$
$$FP_i = F_{pi}O_tE_t$$

are the capital cost, operating cost, and fuel cost portions, respectively. B_{ci}, O_{ci}, and F_{pi} are annualized capital cost, yearly operations expenses, and yearly fuel price. The thermal efficiency of the boiler, assumed to be 88 percent is represented as E_t. Thermal output (O_t) is calculated by multiplying the E/T ratio (ET), the ratio of electrical output to steam and thermal output (expressed in Btu(e)/Btu(t)), to installed capacity:

$$O_t = 3415I_c/ET$$

Total revenue in year i (T_i) is the sum of avoided cost and thermal revenue:

$$T_i = AR_i + TR_i \qquad [17]$$

Operating Costs

Operating costs in year i, O_i, consist of the yearly values of operation and maintenance expenses (OM_i), fuel costs (F_i), insurance (IN_i), property taxes (P_i), interest payments on loans (K_{li}), and accelerated depreciation (D_{fi}):

$$O_i = OM_i + F_i + IN_i + P_i + K_{li} + D_{fi} \qquad [18]$$

Each of these components are based on input parameters and are escalated where applicable. Depreciation is calculated the same as reported earlier (with adjustments for applicable equipment lifetimes in nonutility ventures).

Interest charges are determined with standard loan calculation methods. The initial loan balance (I_o) is determined by:

$$I_o = f_lI$$

where f_l represents the fraction of the project financed by loans. Interest payments are calculated with:

$$K_{li} = k_lI_i$$

where k_l is the interest rate on the loan, and I_i as the remaining loan balance in year i. Loan payments (L) are calculated with the standard annuity equation:

$$L = L_ok_l/(1 - (1 + k_l)^{-N})$$

where N is the length of the loan (assumed to be equal to equipment lifetime and book life). Principal payment (P_i) in year i is calculated by subtracting interest payments from the loan payment, $P_i = L - K_{li}$, and $I_i = I_{i-1} - P_i$.

Income and Profitability

After tax income (AT_i) in year i is determined by applying taxes and tax credits to net income:

$$AT_i = NI_i - T_{fi} \qquad [19]$$

where net income (NI_i) in year i is calculated by subtracting operating costs from revenues, $NI_i = R_i - O_i - D_{fi} - T_{si}$. State tax in year i ($T_{si}$) is calculated by:

$$T_{si} = t_s(R_i - O_i - D_{si}) - (STC \times I)$$

where D_{si} is State depreciation and STC is State energy tax credit. Federal tax (T_{fi}) is calculated by:

$$T_{fi} = tNI_i - (ITC \times I) - (ETC \times I)$$

where ITC and ETC are the applicable tax credits defined earlier.[6]

After tax cash flows (CF_i) are then calculated by:

$$CF_i = AT_i + D_{fi} + (ITC \times I) - (ETC \times I) - P_i \qquad [20]$$

In addition, the investment and energy tax credits are added to the initial year cash flow.

The profitability measures (internal rate of return, payback period, and net present value) can be calculated from this stream of cash flows using standard procedures. The internal rate of return is the expected percentage return on invested capital. Firms will often set a required IRR level (i.e., the "hurdle rate") which a project must meet when making new investment decisions. The length of the project's payback period, the number of years necessary for project revenues to payback the initial outlay, is also used as a screening tool. Net present value provides information on: 1) whether the project will provide positive returns after discounting for the time value of money, and 2) the relative level of income provided by the project. All of these tools can be used to compare alternative investment projects.

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[6] An additional form of tax credit has been proposed for renewable technologies, the production tax credit. This tax credit is based on the electricity generated by the facility. For the tax policy analysis conducted in ch. 8, the production tax credit is calculated by multiplying a tax rate in cents/kWh times generation in kWh. The tax policy discussion assumes that the credit stops being applied when the cumulative credit equals the current energy credit value.

Chapter 9

The Commercial Transition for Developing Electric Technologies

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Chapter 9

The Commercial Transition for Developing Electric Technologies

INTRODUCTION

This chapter discusses past development of the electric generating and storage technologies examined in this assessment, and discusses their commercial outlooks. Factors which constitute serious impediments to widespread commercial deployment in the 1990s—*assuming a demand for additional generating or storage capacity*[1]—are identified. Deployment levels will depend on a combination of changes in cost, performance, uncertainty, and other changes in the commercial environment within which the technologies are developing.

STATUS AND OUTLOOK FOR THE DEVELOPING TECHNOLOGIES

Solar Photovoltaics

History and Description of the Industry

Photovoltaic cells (PVs) first were developed in the 19th century. In the 1950s and 1960s, a combination of technical breakthroughs and the need to power spacecraft stimulated substantial cost reductions, performance improvements and wider applications. During this period, Federal support, channeled primarily through the space program, was the dominant stimulus to the technology's progress.

In the 1970s PVs entered larger terrestrial markets, the most important of which was power generation in remote locations. A notable trend during the 1970s was the growing support for PVs by large petroleum-based companies and the Federal Government. In 1978, Federal support was solidified by the passage of several key laws which provide for a program of research, development, and demonstration and for direct Government purchase of large numbers of solar cells.[2]

From 1980 to 1985, about 30 laboratories across the country were conducting PV research.[3] By 1985, the price of PV modules decreased 80 percent (in constant dollars) from $35,400/kWe in 1976 to $7,000/kWe in 1984; performance also improved markedly. The volume of sales increased rapidly as world PV shipments increased over a hundredfold from 240 kWe in 1976 to 25,000 kWe in 1984. Total revenues increased twentyfold, from $6.8 million to $174 million during the same period.[4]

In the 1980s the PV industry changed considerably. By 1985, the industry consisted mainly of companies which were affiliated with large multinational petroleum-based corporations. By the early 1980s, many companies sought to concentrate their operations towards the raw material end of the production process, emphasizing cell or module production. At the other end of the production chain, however, decentralization occurred, i.e., companies sold off or closed down operations involving other system components than the PV arrays themselves. As the technologies developed and market prospects changed, businesses also shifted emphasis among the different PV systems.

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[1] This assumption is an important one, as a general lack of demand for additional generating capacity could itself constitute the major impediment to the deployment of the technologies in the 1990s.

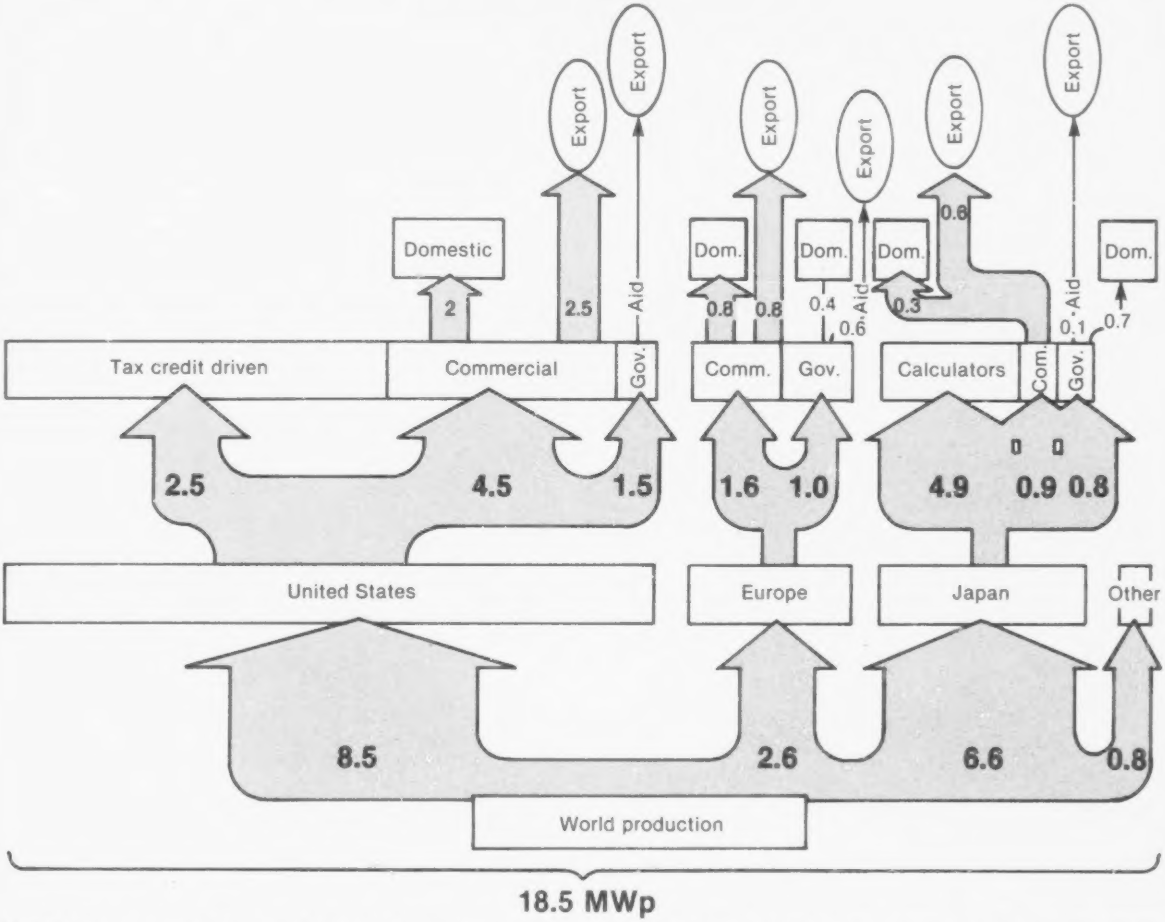
[2] The most important laws were: 1) the Federal Photovoltaic Utilization Act of 1978 (Public Law 95-619, Part 4); 2) the Solar Photovoltaic Energy Research, Development, and Demonstration Act of 1978 (Public Law 95-590); and 3) the Department of Energy Act of 1978 (Public Law 95-238, Section 208).

[3] Larry N. Stoiaken, "A New Generation of Photovoltaics. Commercialization Efforts Gain Momentum," *Alternative Sources of Energy*, vol. 67, May/June 1984, pp. 6-15.

[4] See: 1) Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics* (Mountain View, CA: Strategies Unlimited, December 1984), OTA contractor report. 2) Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 1995. A Strategic Technology & Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984).

The market during the first half of the 1980s is depicted schematically in figure-9-1. During this period the United States dominated world production, with Japan ranking a distant second. The end-use markets for 1984 are broken down in table 9-1. The table highlights the importance of the U.S. central station market both as a fraction of the U.S. market and of the world market. The application of the Public Utility Regulatory Pol-

Figure 9-1.—1984 World Photovoltaics Supply


Export
Export
Export
Export
Export
Export
Domestic
Dom.
Dom.
Dom.
Dom.
2
2.5
Aid
0.8
0.8
0.4
Aid
0.6
0.6
0.3
0.1
Aid
0.7
Tax credit driven
Commercial
Gov.
Comm.
Gov.
Calculators
Com.
Gov.
2.5
4.5
1.5
1.6
1.0
4.9
0
0
0.9
0.8
United States
Europe
Japan
Other
8.5
2.6
6.6
0.8
World production
18.5 MWp

SOURCE: Strategies Unlimited, "Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s," contractor report prepared for the Office of Technology Assessment, U.S. Congress (Mountain View, CA: Strategies Unlimited, Dec. 7, 1984).

Table 9-1.—Estimated Magnitude of End-Use Markets for Photovoltaics, 1984

Market sector	MWe(p) shipped worldwide
World consumer products	5
U.S. off-the-grid residential	2
World off-the-grid rural	0.2
Worldwide communications	5
Worldwide PV/diesel	2
U.S. grid-connected residential	0.1
U.S. central station and third-party financed projects	10
Total MW	24.3
Japanese grid-connected	—
Total MW	25
Price ($/Wp)	$7
Revenues ($ M)	$175

SOURCE: Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance Cost and Market Forecast to 1995: A Strategic Technology and Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984).

icies Act of 1978 (PURPA) and favorable Federal and State (especially California) tax policies was very important in encouraging the deployment of photovoltaics in these facilities.

Federal support for photovoltaics during the first half of the 1980s shifted considerably in emphasis. Direct expenditures in support of photovoltaics declined in importance after peaking in 1980-81, but they continued to have a substantial effect on the development of the technology (see table 9-2). While the Federal Government has concentrated on high risk research and development (R&D) with potentially high payoffs, some direct support was provided elsewhere. Export promotion was recognized as an important element in any program to encourage photovoltaics and assumed a more prominent position among Federal efforts in the 1980s. The Federal Government also continued to support a major demonstration project in California. As direct Federal support declined, indirect support for photovoltaics through tax incentives increased during this period and strongly influenced the rate of progress in the industry.

Industry Outlook and Major Impediments

The 1990s likely will witness rapid growth in the application of hybrid photovoltaics/diesel power systems in remote areas, primarily overseas. Indeed, this market could dominate world PV deployment during the period. Also very important will be grid-connected PV plants in the United States and in Japan. At the same time, the worldwide communications and consumer-products markets will continue to be of major significance to the industry. The magnitude and relative importance of different market segments, and the character of the industry itself, will depend heavily on whether or not the Federal Renewable Energy Tax Credit (RTC) is extended beyond 1985. The exact effect of either action, however, is difficult to accurately predict.

Table 9-2.—Federal Program Funds in Support of Developing Technologies (millions of dollars)

	Year											
Technology	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986 (requested)
Wind	7.9	14.4	27.6	35.5	59.6	63.4	54.6	34.4	31.4	26.5	29.1	20.8
Photovoltaics	5.2	21.6	59.7	76.2	104.0	150.0	152.0	74.0	58.0	50.4	57.0	44.8
Solar thermal	13.2	20.6	79.1	114.7	109.3	135.0	120.0	56.0	50.0	43.9	35.5	28.4
Geothermal	28.0	78.3	76.7	132.9	188.4	171.0	156.3	86.6	73.6	30.5	32.1	12.0
AFBC	2.0[a]	7.0	21.2	24.5	23.6	25.9	11.4	0.3	4.9	1.4	18.7	17.3
Surface coal gasification[b] (includes IGCC)	116.3	117.7	143.2	208.2	122.4	123.3	70.0	54.2	39.0	36.5	32.0	15.0
Fuel cells[c]	n/a	3.0	17.8	33.0	41.0	26.0	32.0	34.5	29.9	42.3	40.8	9.3
Batteries[d]	2.9	6.8	9.7	11.2	15.3	20.3	13.9	12.9	12.8	12.8	8.4	6.3
CAES	0.0	0.6	1.2	4.5	4.5	3.2	2.1	2.0	0.0	0.0	0.0	0.0
Total	175.5	270.0	436.2	640.7	668.1	718.1	612.3	354.9	299.6	244.3	253.6	153.9

[a] OTA estimate.

[b] Does not include support from the Synthetic Fuels Corp.

[c] Includes funding for all fuel cells R&D and is not restricted to phosphoric acid fuel cells.

[d] The funding levels listed are the estimated levels of support for *all* stationary batteries, including but not restricted to lead-acid batteries and zinc-chloride batteries. The estimates assume that roughly 50 percent of the funding for DOE's Electrochemical Program is applicable to stationary batteries.

SOURCE: U.S. Department of Energy, *Congressional Budget Request: FY 1986* (Washington, DC: U.S. Government Printing Office, 1985) and the corresponding documents for preveious years.

If the RTC is not extended in any form, the overall level of deployment is likely to be greatly diminished and it is likely that the largest markets would be the worldwide PV diesel markets and grid-connected applications in Japan. Important, but considerably smaller markets would be world consumer products, remote communications systems, and, finally, grid-connected power systems in the United States.

Termination of the tax credits would have especially severe effects on grid-connected central station applications involving third-party ownership. According to one analysis, this sector by the end of 1986 would shrink by 35 to 85 percent of what it would be with a continuation of the tax credit; by 1990, it would be 5 to 10 times smaller (see table 9-3).[5]

The character of the industry might change as well, with the larger companies in the business withdrawing or greatly reducing their involvement. As a result of depressed oil prices, the oil companies are already cutting back their involvement outside of the petroleum industry.[6] Less favorable tax treatment of PV investments could cause these firms to scrutinize their commitment to photovoltaics even more closely.

Smaller firms, particularly those heavily devoted to the central station market, may be hit hardest. Of special importance is the small segment of the industry dedicated to the concentrator technologies. Several of these companies are quite small. Expiration of the RTCs is likely to severely affect these businesses, greatly limiting the deployment of this promising PV option in the 1990s.[7] Industry dominance could then pass swiftly to the Japanese and the Europeans, whose aggressive and effective PV programs could enable them to dominate overseas markets, and, perhaps, even to capture a large portion of U.S. central station markets by the end of the century.

If, however, the tax credits are extended in some form, the results could be quite different. First, and most directly, for a given photovoltaic system, the level of demand in the United States could be higher than it otherwise would be. Second, the actual cost and performance of PV systems would improve, as the higher demand stimulated innovation and high volume production. This in turn could encourage growth in demand both in the United States and overseas. Finally, larger deployments in the near term would in many other ways accelerate subsequent deployment of photovoltaics. The infrastructure necessary to produce, deploy, and operate PV systems would develop more rapidly, overall experience with the technology would be greater, and institutions—e.g., utilities, public utility commissions, local permitting authorities, and others—could adapt sooner to the technology.

Table 9-3.—Projected 1986 Photovoltaic Shipments by Domestic Manufacturers

	With tax credit expiration		With extended tax credits	
Market sector	Shipments (MW)	Share of market (percent)	Shipments (MW)	Share of market (percent)
Residential, non-grid-connected	5	12.5-7.7	8-10	10.0-8.3
Residential, grid-connected	1	2.5-1.5	2-5	2.5-4.2
Electric utility (third party)	10-25	25.0-38.5	40-60	50.0
Water pumping	2-3	5.0-4.6	3-7	3.8-5.8
Communications	7-9	17.5-13.8	9-11	11.2-9.2
Other industrial (includes government experiments)	5-7	12.5-10.8	8-12	10.0
International	10-15	25.0-23.1	10-15	12.5
Totals	40-65	100.0-100.0	80-120	100.0-100.0

SOURCE: Jet Propulsion Laboratory, *Effects of Expiration of the Federal Energy Tax Credit on the National Photovoltaics Program* (Pasadena, CA: Jet Propulsion Laboratory, 1984), DOE/ET-20356-15.

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[5] Jet Propulsion Laboratory, *Effects of Expiration of the Federal Energy Tax Credit on the National Photovoltaics Program* (Pasadena, CA: Jet Propulsion Laboratory, 1984), DOE/ET-20356-15.

[6] Winston Williams, "Big Oil Starts Thinking Smaller," *New York Times*, Mar. 17, 1985, sec. 3 (Business), pp. 1ff.

[7] Jet Propulsion Laboratory, *Effects of Expiration of the Federal Energy Tax Credit on the National Photovoltaics Program*, op. cit., 1984.

The cumulative effect of extension of the RTC on market size and distribution could be considerable. Virtually all market segments would be larger, some considerably more important than they otherwise might be. Dramatic growth could occur in the volume of sales of photovoltaics for use in PV/diesel hybrid systems in remote overseas applications. This market quickly could come to dominate the international PV market. The U.S. central station market would also be much larger.

Extension of the RTCs also will affect the relative importance of different PV designs. Rapid growth in the deployment of concentrator systems could be stimulated, along with other systems that are favored in central station applications.

Continuation of Federal tax support also could strengthen the position of U.S. manufacturers over foreign competitors—both here and overseas. Overseas competitors, especially the Japanese, are moving rapidly ahead in PV—often with the support of their governments. Tax credit support could serve to slow the erosion of the U.S. position in the industry and perhaps even reverse the trend.

While the issue of the RTC dominates current discussion of the outlook for the photovoltaics industry, a broad range of other factors will affect the prospects for photovoltaics during the 1990s. These are discussed below.

Equipment Cost and Performance.—If PV systems in the 1990s were identical to those available today, they probably could not compete extensively and successfully with the alternatives in U.S. grid-connected applications. Current levels of cost and performance are too high. Investments in both R&D and in industrial capacity to mass produce the technology will be required. The present status of the technology and the changes necessary for extensive commercial application in the 1990s are discussed in chapter 4.

The Risk of Obsolescence.—The technologies of photovoltaics are evolving rapidly. This rapid rate of change may discourage would-be investors from investing in production lines out of fear that their investments could quickly become outdated in the event of technological breakthroughs. Some industry observers think that this is the reason the U.S. industry has been reluctant to invest in the facilities necessary to mass produce crystalline silicon modules. Instead, it largely has opted for the longer term payoff which might be obtained from the less mature amorphous silicon technology. Should progress in the amorphous technology prove slower than expected, the relative lack of emphasis in the U.S. industry on commercial production of crystalline silicon may delay commercial deployment of photovoltaics, and foreign competitors, most likely the Japanese, may seize the opportunity to increase their market share by selling crystalline silicon modules in the United States and abroad.[8]

Solar Resource Assessment.—The current knowledge of the solar resource in the United States is insufficient for the optimum design and siting of PV plants. The best available information is the SOLMET data, based on several years of readings at 26 sites.[9] The SOLMET data gives monthly averages of solar insolation for each hour at typical geographic locations.

While such figures are useful for calculating generic capacity factors and peak system outputs for a particular region, the characteristics of a particular site may be significantly different than the average. Before utilities can integrate photovoltaics into their operations, they must have a detailed understanding of PV operating dynamics, based on a minute-by-minute understanding of the insolation patterns at a site.[10]

Also, to optimize the design of PV modules, it will be necessary to understand much more about the detailed spectral and directional distributions of light energy as a function of time-of-day and day-of-the-year. Such information not only influences the decision of whether or not tracking systems are cost effective, but it also affects the detailed design of the cells, since the light absorption and current carrying capacity of these cells must be carefully matched to the solar spectrum.[11]

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[8] Roger G. Little, President, Spire Corp., testimony presented in hearings held by the Subcommittee on Energy Development and Applications, House Committee on Science and Technology, U.S. Congress, *The Status of Synthetic Fuels and Cost-Shared Energy R&D Facilities* (Washington, DC: U.S. Government Printing Office, 1984), No. 106, June 6, 7, and 13, 1984, pp. 386-389.

[9] Roger Taylor, *Photovoltaic Systems Assessment: An Integrated Perspective* (Palo Alto, CA: Electric Power Research Institute, September 1983), EPRI AP-3176-SR.

[10] Ibid.

Cost and Performance Data.—A serious obstacle to timely deployment of photovoltaics in any application is the lack of accurate and useful information about the technology and its economics. What are the specific capital costs of a specific PV system? How will it perform at a specific locality? What kinds of operating and maintenance expenses might be incurred? This problem already has been an obstacle in overseas applications where investors often do not know enough about PV cost and performance or lack the analytical means to adequately compare photovoltaics to conventional alternatives.[12]

Standards.—The lack of standard definitions, testing methods, and other criteria relating both to PV modules and balance of system equipment reportedly has hindered development and deployment. It is thought by some that the application of standards ultimately will expedite the commercial application of the technology. Several groups are working on such standards, though who should set and enforce them is a matter of considerable controversy within the industry.

Warranties.—The extent to which warranties are available, and the nature of such warranties, will strongly affect the commercial success of PV systems in the 1990s. It was not until late 1984 that anyone in the industry offered even a limited warranty and an Underwriters Laboratories listing for a PV module.[13] Vendors will be reluctant to provide strong extended warranties until the technology has been adequately proven in real conditions. This requirement likely will put relative newcomers such as amorphous-silicon modules at a disadvantage until sufficient experience is built up.[14] The ability to provide extended warranties will be influenced greatly by the amount of capital available to the industry, which in turn will depend on market size and profit margins.

Utility Energy and Capacity Credits, and Interconnection Requirements.—Grid-connected PV plants can be owned by utilities or by others. As discussed earlier with wind systems, low energy credits, low capacity payments, and stringent interconnection requirements discourage deployment by nonutilities. Even where the possibility exists that credits could drop during the lifetime of a project, investment is discouraged. Also, any difficulties (such as delays) encountered in seeking to obtain favorable credits or interconnection requirements discourages nonutility deployment.

Overseas Markets.—Overseas markets will serve to encourage mass production of PV systems and hence lower costs. The larger market also will serve to indirectly stimulate technical development which could lead to further reduced costs or improved performance. As a result of such improvements the exploitation of overseas markets could help ensure that U.S.-made systems remain competitive in the domestic market.

Current evidence suggests that the U.S. photovoltaics industry is not as successful as it could be in overseas markets; as mentioned earlier, the situation will be exacerbated with the scheduled termination of the renewable energy tax credits. Meanwhile, competitors—especially the Europeans and the Japanese—are more actively and successfully developing these markets, often supported by favorable government programs. Failure to fully exploit export markets could slow the development of U.S. photovoltaics, extend the period required before extensive grid-connected applications will occur, and increase the likelihood that large segments of the U.S. market will eventually be served by foreign vendors.

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[11] OTA staff interview with Charles Gay, Vice President, Research and Development, ARCO Solar, Inc., Aug. 10, 1984.

[12] For example, see: Clyde Ragsdale, manager of Marketing for Solavolt International, testimony presented to the Subcommittee on Energy Development and Applications, House Committee on Science and Technology, U.S. Congress, Hearing on the Current State and Future Prospects of the U.S. Photovoltaics Industry, Sept. 19, 1984.

[13] "Slants and Trends," *Solar Energy Intelligence Report*, vol. 10, No. 43, Oct. 29, 1984, p. 339.

[14] "Intense Competition Among Five Silicon Technologies Seen for PV: Maycock," *Solar Energy Intelligence Report*, Apr. 2, 1984, p. 110.

Solar Thermal Electric Plants

History and Description of the Industry

By 1879, the French had converted solar radiation into thermal energy and produced small quantities of electric power. Though this work led to the operation of several demonstration units, the devices proved to be prohibitively expensive to build and operate, and the idea of producing electric power from solar thermal energy was largely abandoned. Not until nearly 100 years later was heat derived from the Sun widely considered as a means of producing electric power.[15]

A variety of solar thermal electric technologies are now being developed. But as discussed in chapter 4, their current status and prospects differ substantially. The solar pond technology faces many limitations that make widespread commercial application within this century unlikely. The prospects for three other technologies—central receivers, parabolic troughs, and parabolic dishes—are brighter. The histories of these technologies in the United States have been shaped by the Federal role in their development. Their prospects in the 1990s likewise probably will also depend heavily on Federal activity between now and the end of the century.

Direct Federal sponsorship of the technologies rose rapidly in the 1970s, spurred by the desire to develop technologies which were less vulnerable to fuel disruptions and price increases, and which had less severe environmental impacts than many conventional technologies. But direct Federal support has declined from $135 million in 1980 to less than $36 million in 1985 (see table 9-2). The impact of the decline was offset in part by an increase in indirect support in the form of tax incentives during the first half of the 1980s. The effects of conservation, which moderated conventional fuel prices, also dampened the prospects for near term-commercial success.

During the latter half of the 1970s and the early 1980s, the central receiver technology progressed rapidly, culminating in 1982 with the operation of a 10 MWe pilot plant, the Solar One pilot facility. Eighty percent of that project's costs were paid by the Department of Energy (DOE). The plant, while not of commercial scale, has operated quite successfully.

Private sector involvement in the central receiver technology has primarily involved electric utilities as well as equipment developers and vendors. These and other private investors, however, have been unwilling to invest in a commercial plant without Government subsidy, until they had evidence of a successfully operating close-to-commercial unit. Yet neither the private nor public sector participants, alone or in cooperation with each other, have been willing to finance a commercial demonstration unit. Various parties have sought ways around this impasse; others have disbanded and moved away from the technology, assuming that the combined effects of Federal spending cutbacks, the impending expiration of the renewable energy tax credits, and other factors preclude extensive commercial deployment in the near term.[16] By mid-1985, work on the central receiver technology was confined primarily to federally supported research and development at DOE's Central Receiver Test Facility and on federally funded efforts at the Solar Energy Research Institute to develop low cost and durable heliostats.

The parabolic troughs, meanwhile, progressed much further into the market place. By the early 1980s, the Federal Government had funded nearly a dozen experiments and demonstrations. The technology had reached the point where it was nearly ready for commercial applications.

The relatively short lead-time of the technology allowed the Luz Engineering Corp. to initiate two projects which could be completed soon enough to exploit the Federal renewable energy tax credits even if they expired as planned at the end of 1985. Because the projects were in California, they could also enjoy State tax incentives, favorable solar insolation levels, and high utility avoided cost energy payments. In December 1984, the first of the two plants, known as Solar Electric Generating System-I (SEGS-I) and capable of producing 13.8 MWe, had begun operating. By February 1985 construction of a second 33 MWe plant (SEGS-II) was initiated and was expected to begin operating by late 1985 or early 1986. Luz designed these systems, coordinated the projects and was an investment partner in them. The remainder of the investment was provided mostly by large institutional investors through a limited partnership. The system's performance was guaranteed for 20 years by Luz Industries (Israel) Ltd., the parent firm, which also provided an insurance policy for the project. Southern California Edison agreed to purchase the power for 30 years. Other than the Luz projects, private sector involvement in the trough technology is limited.

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[15] Ken Butti and John Perlin, *A Golden Thread* (New York: Van Nostrand Reinhold Co., 1980).

[16] The central receiver teams at Martin Marietta, Boeing, Rockwell, and to a large extent McDonnell Douglas are being disbanded. In addition, the government and utility support teams at Sandia Livermore, Sandia Albuquerque, Jet Propulsion Laboratory and Electric Power Research Institute also are being disbanded and the personnel being transferred to other positions. See Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984).

Federal support for parabolic dishes developed somewhat later than for the central receiver and troughs. As a result, their development has lagged behind that of the other solar thermal electric technologies. However, the efforts of over half a dozen firms, coupled with direct Federal support and other favorable conditions (including Federal and State tax incentives and the provisions of PURPA) fostered rapid development of the technology, especially during the first half of the 1980s. Notable was the fact that among the firms whose support of parabolic dishes increased during the period were several who previously concentrated on either the central receiver or parabolic troughs.[17]

By mid-1985, a privately financed commercial dish facility had been installed by the LaJet Energy Co. in southern California. It was financed by the parent company, La Jet, Inc.—a privately held petroleum exploration, drilling, and refining company—and through limited partnerships. Meanwhile, other commercialization efforts were proceeding, the most important of which appeared to be the joint venture of McDonnell Douglas, an aerospace corporation active in the energy field since the early 1970s, and United Stirling, AB, a Swedish manufacturer of Stirling engines.

Industry Outlook and Major Impediments

As discussed in chapter 4, widespread commercial deployment of solar thermal electric technologies is unlikely unless costs are reduced, and performance improved. Moreover, investor interest is not likely to be forthcoming until performance is demonstrated.

As with photovoltaics, wind, and geothermal technologies, the Federal Government's policies strongly influence the outlook for the solar thermal electric industries. Without either an increase in direct Federal support or an extension of the renewable energy tax credits beyond 1985, none of the solar thermal technologies is likely to be used much commercially in the 1990s.[18] After 1985, the limited solar thermal electric industry which exists today is likely to shrink rapidly. The commercial activities of Luz in solar troughs and La Jet in parabolic dishes probably would be cut back substantially, as would the efforts of other smaller, entrepreneurial companies in the industry. Only the largest companies may be able to sustain the involvement required to successfully deploy the technology in the 1990s.[19]

Even with increased direct Federal support and favorable tax policies, with the necessary cost and performance improvements, and with commercial demonstrations, success is still by no means guaranteed for these technologies in the 1990s. There are other potential impediments to their deployment. Among these might be problems relating to energy credits, capacity payments, and interconnection requirements. Problematic too could be the lack of widespread experience with the technology; and licensing and permitting delays (among which extensive land impacts and access to water might figure importantly).

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[17] McDonnell Douglas, now a major supporter of the dish technology, previously was heavily involved with the central receiver. Acurex Solar Corp. presently is emphasizing dish technologies too, after having focused its solar thermal electric efforts on trough technology. Acurex still is working on trough technology, but it is emphasizing the use of the technology for industrial process heat or cogeneration.

[18] This was reflected in the testimony of Frank F. Duquette before the U.S. Congress on Mar. 1, 1984. He stated that:

> The nearer term technology at this stage of development, still requires Federal support to reduce technical risk and validate commercial or near commercial applications. Private industry is unable to assume the entire burden of completing the R&D tasks remaining for this current generation of technologies.

(Frank F. Duquette, Chairman, Solar Thermal Division, Solar Energy Industries Association, testimony presented to the Subcommittee on Energy Development and Applications, Committee on Science and Technology, U.S. Congress, Mar. 1, 1984.)

[19] See: 1) Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984; 2) Peter B. Bos and Jerome M. Weingart, *Impact of Tax Incentives on the Commercialization of Solar Thermal Electric Technologies* (Livermore, CA: Sandia National Laboratories, August 1983), SAND 83-8178.

In some cases, problems also may develop with regards to the Fuel Use Act. The leading trough technology, that employed at the SEGS-I and II plants in California, requires natural gas to supplement the solar energy in producing steam for the steam turbines. Currently, the Fuel Use Act prohibits the use of gas and oil in many new generating facilities except under special conditions. While exemptions to the law may be obtained, the law could delay or even prohibit construction of oil- or gas-using facilities.

The following sections discuss for each technology some of these impediments as well as problems which are crucial to the individual technologies.

Central Receivers.—For the central receiver technology, one impediment stands out among all others—the lack of a commercial-scale demonstration plant. Unless such a plant is initiated very soon and begins operating before the end of the decade, the prospects for this technology in the 1990s are very limited. Should a demonstration plant be initiated later than this, it will be extremely difficult in the time remaining to overcome the many other obstacles blocking significant contribution by this technology to power production in the 1990s. In particular, the lack of a commercial demonstration project in the near future is likely to lead to the continued disbanding of organizations originally established to deploy both a demonstration plant and subsequent commercial units.

Several attempts to finance demonstration units by private sources have been initiated but have failed. Hence, it appears unlikely that such plants will be built without Government support.[20] Without timely Government action, this technology's prospects are likely to be severely limited during the 1990s. Other major impediments which could limit deployment, even if there is prompt construction of a demonstration plant, are: 1) the high cost of heliostats, 2) technical problems with the central receiver and other components, and 3) various nontechnical problems relating to such things as licensing and permitting.

Parabolic Troughs and Dishes.—Unlike the ponds and central receivers, parabolic dishes and parabolic troughs, financed by private investors assisted by State and Federal renewable energy tax credits, already have been deployed and operated in commercial-scale units. Both for dishes and troughs, the combination of cost and performance characteristics and numerous uncertainties at present mitigate against private sector investment that is not in some manner accompanied by Government support. How these conditions will change over the next 5 to 10 years will depend on the interaction of a complex of variables. Estimates and opinions of what will happen range widely; each technology and each particular subvariety of technology has its proponents and detractors.

Generally speaking, capital costs must be reduced and performance improved if the technologies are to be deployed widely. To some extent, this can be fostered by research oriented towards incremental improvements of the commercial-scale systems now operating. Also necessary will be adequate information on the solar resources. And if the technologies are to be extensively deployed in the 1990s, perhaps the most pressing need is to reduce uncertainty and to increase demand to the point where economies of scale can drive costs down.

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[20] The need for further government support repeatedly surfaces both in the literature and in conversations with knowledgeable individuals. See for example: 1) L.K. Ives and W.W. Willcox, "Economic Requirements for Central Receiver Commercialization," *Proceedings of STTF (Solar Thermal Test Facility) Testing for Long Term Systems—Performance Workshop, Jan. 7-9, 1984* (Albuquerque, NM: National Technical Information Service, July 1984), PC A15/MF A01, pp 61-67; 2) Edgar A. DeMeo, "Molten Salt Solar-Thermal Systems," *EPRI Journal*, vol. 8, No. 12, December 1983, pp. 38-41; 3) McDonnell Douglas, "Response by McDonnell Douglas to General Workshop Discussion Questions," submitted to OTA in response to written questions submitted in connection with OTA Workshop on Solar Thermal Electric Technologies, 1984; 4) Arizona Public Service Co., et al., *Solar Thermal Central Receiver Development Plan for Molten Salt Technology*, mimeo, prepared for U.S. Department of Energy, Jan. 31, 1984; and 5) C.J. Weinberg (Pacific Gas & Electric), letter to Howard S. Coleman (Department of Energy), dated Dec. 21, 1984.

The extent to which uncertainty will be reduced by the 1990s depends heavily on the amount of additional capacity installed for each of the systems during the next 5 years. Should the tax credits be extended, additional trough and dish systems probably will be installed, serving to reduce considerably the importance of uncertainty as an impediment to commercial deployment. The mounted-engine dishes in particular—where uncertainty now is especially great—could benefit from greater deployment of commercial-scale units, and improved commercial prospects might result. Under such conditions, the mounted-engine parabolic dishes could eliminate the current lead enjoyed by parabolic troughs among the solar thermal technologies. If the engines perform well, the parabolic dish technology could provide serious competition to the troughs and to other generating alternatives in the 1990s.

Without either sizable tax credits or greater direct Government support, however, fewer and perhaps no additional trough or parabolic dish units may be installed. Indeed, the private enterprises which are presently pursuing the technologies may completely cease activities in support of the technologies altogether. Our market analysis suggests that only one of the parabolic dish developers is likely to maintain a significant effort to support the technology if the renewable energy tax credits cease to be available at the end of 1985.[21]

Wind Turbines

History and Description of the Industry

Wind turbines first were used to generate electricity in Denmark nearly 100 years ago. Later, in the early 1930s through the late 1950s the technology was deployed in the United States, predominantly in rural areas. As transmission lines were extended to these areas and cheap electricity provided, the wind turbines ceased to be an attractive option. By the 1960s and early 1970s, technical progress slowed to a crawl and deployment continued at only a very low level.

Interest in wind turbines resurfaced in the 1970s when energy costs skyrocketed, fuel supplies became uncertain, and environmental concerns grew. The resurgence was strongest in the United States and in Europe, especially in Denmark. During the early 1970s, major government programs both in the United States and abroad emphasized the development of large, multi-megawatt wind turbines, though important work applicable to smaller machines also was supported. Outside of government-subsidized programs, smaller units with ratings less than 100 kWe were favored, as these offered the most immediate commercial applications.

By mid-May 1985, wind turbines—mostly small units—with a total rated capacity of over 650 MWe were installed nationwide. Most—about 550 MWe—were in California's wind-farms, which became the focus of the worldwide wind turbine industry. Several basic interrelated elements appear to have shaped development during this period.

First, developers of the large multi-megawatt wind turbines encountered serious technical difficulties. In the United States, the Federal Government cut back its direct support of wind research and development (see table 9-2). The industry, heavily dependent on Federal support, shifted away from the large machines when the Federal aid receded and concentrated on small wind turbines which afforded a more immediate commercial promise.

Second, a combination of favorable circumstances in California prompted rapid growth in the deployment of grid-connected wind turbines. Among these circumstances were the adoption of PURPA Section 210, high electric-utility avoided costs, availability of an excellent and accessible wind resource which had been carefully assessed, favorable Federal and State tax treatment; and favorable treatment by the California Energy Commission and Public Utility Commission.

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[21] Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984; Peter B. Bos and Jerome M. Weingart, *Impact of Tax Incentives on the Commercialization of Solar Thermal Electric Technologies*, op. cit., August 1983.

Finally, technical development of smaller sized wind turbines proceeded very rapidly as costs declined and performance improved. The extremely favorable conditions in California encouraged the initial commercial deployment of equipment which was new and not fully proven. The processes of research, development, and commercialization came together into one step as California's wind farms became *de facto* open-air laboratories. While this greatly accelerated the development of the technology, it also led to inevitable mechanical failures and inadequacies associated with an emerging and immature technology.

In 1984, there were about 100 wind turbine manufacturers worldwide. They were mostly small, independent businesses dedicated exclusively to the wind industry, and owned and operated by risk-taking entrepreneurs without extensive business experience.[22] Most of the companies had limited financial reserves, and depended on company growth to cover their past debts and provide working capital. Approximately 70 of the companies in 1984 provided mostly turbines of sizes less than 50 kWe. About 30 companies were active in wind farms and of these, six accounted for 95 percent of the world wind-turbine sales in 1983.[23]

In other words, the world wind-turbine industry presently consists of many small firms, but it is dominated by a few manufacturers who possess an advantageous combination of adequate equipment and financial resources. However, even these six companies are relatively small. For example, Energy Sciences, Inc., the third ranking U.S. supplier in 1983, sold $17.5 million worth of wind equipment in 1983. By comparison, the smallest company on the Fortune 1000 list had sales of over $122 million in 1983.[24]

Companies based in the United States dominated the world market for wind power equipment in 1983, accounting for an estimated 72 percent of world sales. But this position is being eroded by foreign competition. By 1984, U.S. manufacturers accounted for 69 percent of world sales of approximately $405 million. The decline of the U.S. position in world markets has been paralleled by its decline in the domestic market as well. The erosion of the U.S. industry's market share is expected to continue. European vendors may achieve parity with U.S. producers in U.S. markets by the end of 1986 and surpass them by 1988. This appears possible due to a superior combination of equipment quality and cost, the latter being greatly affected by the strength of the U.S. dollar. In addition, European vendors have been very aggressive in exploiting foreign markets.[25]

During the 1980s, the industry has been highly competitive; many companies have entered the business and many others have withdrawn. Currently, the number of firms is declining.

The great bulk of wind turbine capacity deployed in the United States is financed by investors other than the electric utilities and orchestrated by *wind farm developers*. While some developers are independent of the turbine manufacturers (the open "merchant" market), a large and growing share of the wind farms is directly affiliated with the turbine manufacturers themselves.[26] This "captive" wind farm market allows vendors to: 1) capture the developer's profits, which generally exceed their own; 2) regulate turbine demand over the span of each year so that demand is not overly concentrated at year-end; and 3) gain better control over adverse publicity relating to turbine performance.

To date, capital for wind farm investment has rarely come from public stock offerings or from venture capitalists. Most investment has been in the form of limited partnerships, either sold directly by the developer or through brokerage firms. Since 1982, major brokerage houses have been involved and their importance in the industry has increased. Some developers, however, use so-called "chattel" sales to avoid dependence on brokerage houses. Each of these financing arrangements has its advantages and problems, and affects wind turbine deployment in a different way. The manner in which financing is obtained therefore will continue to be of critical importance to the industry. (See chapter 8 for more details on financing arrangements.)

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[22] See for example comments of Bror Hanson in *Alternative Sources of Energy*, vol. 50, July/August 1981, p. 5.

[23] Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984.

[24] Ibid.

[25] Ibid.

[26] This vertical integration typically takes several forms: the manufacturer may itself obtain the land, utility contracts and capital required for the wind farm; or 2) it may simply acquire a developer, or form exclusive relationships with a developer or an equipment distributor.

Industry Outlook and Major Impediments

As mentioned earlier, wind turbines during the first half of this decade have benefitted from favorable tax treatment; chapter 8 discusses the effects of specific Federal tax provisions on wind turbine economics and highlights their importance. Potential tax changes, therefore, are of concern to the industry. The tax change of most immediate concern is the scheduled expiration of the Federal renewable energy tax credit (RTC) at the end of 1985.

Expiration of the RTC is likely to result in a major shake-out in the U.S. wind industry. Barring unexpected increase in electric utility involvement, demand for wind turbines probably will drop sharply, and many small firms are likely to collapse. Only larger firms with sufficient capital to further develop medium-sized turbines *and* weather a period of intense competition and relatively low sales will survive. Though the size of the industry and the variety of firms could be greatly diminished, and though technical progress is likely to be slowed considerably, many industry observers believe that the industry could survive, and perhaps even benefit, from a termination or phase-down of the RTC.

Though the RTC has stimulated technical development and commercial deployment, which otherwise could not have occurred in the early 1980s, they also have been abused by some investors as short-term tax shelters.[27] Such abuse has prompted Federal tax fraud investigations and hurt the reputation of the industry.[28]

Alternatives to a simple extension of the current Federal credits have been suggested. One would gradually phase-out the tax credits over several years; this might help the industry complete the commercial transition from small tax-subsidized turbines to unsubsidized and economic medium-sized units. Another would establish a system of credits based on energy production rather than capital investment;[29] these are discussed in greater detail in chapter 10.

Aside from the immediate issue of the RTC, other possible circumstances could also slow the development and deployment of competitive, medium-sized turbines in the 1990s. Problems relating to the following could arise.

Equipment Quality.—Technical improvements are necessary if wind turbines are to compete without subsidy. While improvements are being made, cessation of the RTC at the end of 1985 and of the California tax credit several years later is likely to severely reduce the capital available to finance development and production of new wind turbine designs. Moreover, the likelihood of smaller markets will reduce the opportunity to actually deploy the units and thereby generate the data necessary for further improvement. The difficulty in financing the redesign and manufacture of new equipment probably will be particularly severe among the small wind turbine manufacturers.

Wind Resource Information.—Detailed wind resource information is crucial to the growth of wind-farms around the country. While current meteorological data allows identification of potential sites,[30] detailed site-specific information must still be gathered for at least 1 to 3 years to adequately assess the potential of specific sites. While site-specific information is being generated at a rapid pace, the lack of such information still could hinder deployment in the 1990s.[31] The need for wind assessment extends to prospective export markets as well, where data are especially inadequate.[32]

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[27] See statement of Bill Adams, San Gorgonio Farms, as quoted in "San Gorgonio Farms (SGF) Will Install 53 Carter Wind System Model 225's," *Wind Industry News Digest*, vol. 4, No. 4, Feb. 15, 1984, p. 3.

[28] Largely in response to tax-shelter abuses, the American Wind Energy Association established an ethics committee to monitor the industry and discourage behavior which harms the long-term interests of the business. See: Burt Solomon, "Windmillers Clean Up Act," *Energy Daily*, vol. 13, No. 12, Jan. 17, 1985, pp. 1 and 3.

[29] Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984.

[30] Battelle, Pacific Northwest Laboratories, *Application Examples for Wind Turbine Siting Guidelines* (Palo Alto, CA: Electric Power Research Institute, March 1983), AP-2906.

[31] See: 1) JBF Scientific Corp., *Early Utility Experience With Wind Power Generation: Goodnoe Hills Project* (Palo Alto, CA: Electric Power Research Institute, January 1984), vol. 3, EPRI AP-3233; 2) Dean W. Boyd, et al., *Commercialization Analysis of Large Wind Energy Conversion Systems* (Palo Alto, CA: Decision Focus Inc., June 1980).

Land Access and Cost of Access.—Access to wind-swept land has in some instances been a problem.[33] Furthermore, costs of access have increased substantially. Development of the wind resource presupposes access at an acceptable cost. These potential problems may slow deployment in the next 15 years.

Cost and Performance Data.—Current cost and performance data are very important to prospective wind turbine investors as well as to utilities, public utility commissions, and the turbine manufacturers themselves. At present such data are difficult to obtain, precluding accurate prediction of wind turbine cost and performance prior to deployment. Efforts are being made in some States to increase the information available on current machines.[34] Where performance data are available, use is often limited by inconsistencies and other problems.

Standard Definitions and Performance Levels.—The effective use of performance data often is limited by inconsistencies; standard definitions might assist investors and others in comparing wind turbines with each other as well as with competing generating technologies. The value of such standards is enhanced when they are provided by an independent and trustworthy source. Of even greater value might be the establishment of minimum standard performance levels which turbine performance must meet in order to receive certification. Many industry observers believe standards should be applied to the industry, though there is disagreement over who should impose the standards and what the standards should be.

Warranties.—Investors, in view of the past poor performance of some wind turbines, are reluctant to invest in hardware unless it is accompanied by a strong warranty. This essentially shifts part of the risk of owning and operating a wind turbine back to the vendor. Because current technology is immature, however, such warranties are in themselves risky and could lead to high costs for vendors. Indeed, some manufacturers have been driven out of business because of these costs.[35] While vendors can purchase "warranty insurance," this insurance has become progressively expensive as insurers have become more cautious with wind turbines.[36] Should the industry be short of capital during the next 15 years, the warranty issue could constitute an important impediment to industry expansion.

Government Permits and Licenses.—Wind farm promoters are expected to encounter problems as they seek approval for their projects from Federal, State, and local regulatory agencies. The most serious problems are likely to be at the local level, where wind farms have already encountered public opposition because of visual and environmental impacts.[37]

Transmission Facilities.—Without access to transmission facilities, even the most attractive site cannot be linked to the grid. Major transmission facilities often require lead-times of 3 to 10 years. Clearly, if candidate wind sites do not already have easy access to transmission lines, serious delays may be encountered. Widespread wind turbine deployment in the 1990s will either be limited to areas which already have access to transmission lines, or if currently remote areas are to be developed, efforts to extend transmission facilities to those areas must be initiated within the next decade.[38]

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[32] S.K. Griffith, et al., *Foreign Applications and Export Potential for Wind Energy Systems* (Golden, CO: Solar Energy Research Institute, 1982), subcontractor report, SERI/STR-211-1827.

[33] R.J. Noun, et al., *Utility Siting of WECS: A Preliminary Legal/Regulatory Assessment* (Golden, CO: Solar Energy Research Institute, May 1981).

[34] The State of California, for example, requires that production and other data (including cost data) be provided on a quarterly basis by all wind project operators in the State. The American Wind Energy Association is developing a voluntary national reporting program similar to California's mandatory program.

[35] For example, see: 1) "How Wind Power Cracks Up," *New Scientist*, Apr. 12, p. 31; 2) Arthur D. Little, Inc., *Wind Turbine Performance Assessment* (Palo Alto, CA: Electric Power Research Institute, 1984), Technology Status Report No. 7, EPRI AP-3447; 3) Larry Stoiaken, "The Small Wind Energy Conversion System Market: Will 1984 Be 'The Year of the SWECS'?" *Alternative Sources of Energy*, vol. 63, September/October 1983, pp. 10-23; and 4) Strategies Unlimited, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s. Wind Turbines, Solar Thermal Electric, Photovoltaics*, op. cit., 1984.

[36] Ronald L. Drew, "Wind Energy. The Present Status of Relevant Insurances," *Alternative Sources of Energy*, vol. 72, March/April 1985, pp. 56-59.

[37] See chs. 4 and 7 for further details.

Utility Energy and Capacity Credits, and Interconnection Requirements.—Low energy credits, low capacity payments,[39] and stringent interconnection requirements discourage deployment by nonutilities. Even where the *possibility* exists that credits could drop during the lifetime of a project, investment is discouraged. Also, any difficulties (such as delays) encountered in seeking to obtain favorable credits or interconnection requirements discourages nonutility deployment.

Overseas Markets.—Over the next decade, foreign markets are likely to be important outlets for wind turbines, especially small machines for remote applications;[40] under some conditions they could be crucial to the survival of major manufacturers. Already, exports account for a sizable share of turbine sales by U.S. manufacturers, and current evidence indicates that many are actively developing overseas markets.[41] The promotion by the companies themselves and by others of overseas sales appears to constitute a major opportunity to nurture the industry and to indirectly foster further refinement of the technology. Difficulties in exploiting these markets (including problems relating to foreign competition) therefore could severely damage the industry, reducing its capacity to supply the domestic markets with turbines of acceptable quality and in the quantities demanded for the 1990s.

Geothermal Power

History and Description of the Industry

In 1904, Italy became the first country in the world to use geothermal energy to produce electricity. In 1923 geothermal resources were tapped in the United States to produce electric power. At that time, a small, remote 250 kWe unit began generating power for a California hotel at The Geysers. Over 35 years elapsed, however, before further capacity was installed in the United States when, in early 1960, the first grid-connected geothermal unit began to generate power at The Geysers. During the following 20 years, further development occurred and by the end of 1983, 1,300 MWe of geothermal capacity were on-line in the United States—more capacity than in any other country. Worldwide, about 3,400 MWe were operating.[42]

Most U.S. geothermal development, located at The Geysers in California, employed direct steam conversion technology. As discussed in chapter 4, however, most U.S. geothermal resources are of lower quality than those found there and cannot be exploited with the conventional technology used at The Geysers. As development activity progressed in the 1960s, the need for different technologies for lower quality resources became evident. Further geothermal development increasingly would require other equipment such as the developing technologies considered in this assessment—dual flash and binary systems.

While the need for technological progress was apparent in the 1960s, it was not until recently that these new technologies began to be deployed in the United States. Several factors, including problems regarding Federal leasing policies and technological questions, served to impede the development of the lower quality geothermal resources. Progress in these matters, along with the passage of PURPA, favorable Federal and State taxes, and high avoided costs, brought commitments to the technologies during the first half of the 1980s. By the end of 1985, a single 47 MWe (net) dual-flash geothermal unit will be in place. One large (45 MWe,net) binary plant will have been installed and at least 30 MWe of small binary plants will be operating. Together these will account for about 122 MWe, or about 7 percent of total U.S. installed geothermal capacity at the end of 1985 (about 1,780 MWe[43]).

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[38] For example, the lack of transmission capacity in California reportedly prevented development of some prime wind sites. Source: OTA staff conversation with Mike Batham, California Energy Commission, November 1984.

[39] For a discussion of capacity credits in the wind industry, see Fred Sissine, *Wind Power and Capacity Credits: Research and Implementation Issues Arising From Aggregation With Other Renewable Power Sources and Utility Demand Management Measures* (Washington, DC: Congressional Research Service, 1984).

[40] See: 1) Birger T. Madsen, "Danish Windmills: A View From the Inside," *Alternative Sources of Energy*, vol. 69, September/October 1984, pp. 24-26; 2) S.K. Griffith, et al., *Foreign Applications and Export Potential for Wind Energy Systems* (Golden, CO: Solar Energy Research Institute, 1982), subcontractor report, SERI/STR-211-1827; 3) Les Garden, "The Overseas Market: Does the Post-Tax-Credit Transition Start Now?" *Alternative Sources of Energy*, vol. 69, September/October 1984, pp. 28-30; 4) Larry Stoiaken, "International Marketing: U.S. Wind Firms Make Their Move," *Alternative Sources of Energy*, vol. 72, March/April 1985, pp. 21-23.

[41] See, for example: 1) "FloWind Signs 'Document of Mutual Interest' With Chinese for 40 Darrieus Turbines," *Solar Energy Intelligence Report*, Jan. 21, 1985, p. 24; 2) Larry Stoiaken, "The Small Wind Energy Conversion System Market: Will 1984 Be 'The Year of the SWECS'?" op. cit., 1983; 3) Larry Stoiaken, "Going International," *Alternative Sources of Energy*, vol. 63, September/October 1983, pp. 24-25.

[42] Ronald DiPippo, "Development of Geothermal Electric Power Production Overseas," *Energy Technology XI, Applications & Economics: Proceedings of the Eleventh Energy Technology Conference, Mar. 19-21, 1984*, Richard F. Hill (ed.) (Rockville, MD: Government Institutes, Inc., August 1984), pp. 1219-1227.

Important to these technological developments has been the Federal Government's support of the industry since the mid-1970s. The first major Federal assistance came in the form of the Geothermal Loan Guarantee Program. This soon was coupled to stepped-up support for research and development (see table 9-2). From 1973 through 1983, approximately $1 billion was spent on geothermal power by the Federal Government, roughly matching industry's expenditures. Direct Federal expenditures in support of the technology, concentrated in DOE and its predecessor agencies, grew from $3.8 million to $171 million in 1980; however, as of fiscal year 1985 this had dropped to $32.1 million. The recent decline in direct Federal expenditures was partially offset by increases in indirect Federal support of the industry through various tax incentives, including the Renewable Energy Tax Credit.

Discovery of geothermal resources has long been associated with oil exploration and development in this country. When geothermal activity picked-up in the 1960s, several oil companies entered the geothermal business. Since then, the oil industry has continued to be deeply involved with geothermal development, and indeed heavily dominates the industry. At the same time, a group of smaller, independent enterprises has sought to develop geothermal power, usually by pursuing the relatively marginal resources.

Among the businesses in the geothermal industry is a core of about two dozen companies capable of sustaining the full effort required to bring geothermal projects to fruition. In addition, there are many other companies and organizations, such as electric utilities, drilling companies, architectural and engineering firms, and the Electric Power Research Institute (EPRI), which support the development and deployment of the technology.[44]

Until the late 1970s, geothermal development was carried out through cooperative ventures between field developers and electric utilities. The field developers located the resource and then worked with the electric utility and architect-engineering firms to design and construct a powerplant. The field developer then would tap the geothermal resource and deliver the hot water or steam "over the fence" to the electric utility. Since 1978, though, PURPA, favorable tax treatment, and high avoided costs have stimulated nonutility investment in power generation projects, and purely nonutility projects have become prevalent in Oregon, California, and Nevada.

Industry Outlook and Major Impediments

By the year 2000, a total U.S. geothermal capacity from 2,600 to about 6,800 MWe may be in place. A sizable portion of this could consist of the developing technologies discussed in chapter 4. Most will be located in California, Hawaii, Arizona, New Mexico, Nevada, and Utah.[45] The degree to which the potential will be realized depends on a variety of circumstances.

As with the other renewable energy technologies, the status of various State and Federal tax incentives will strongly influence deployment levels. As mentioned in chapters 4 and 8, the tax incentives make geothermal investments much more attractive and have been especially important in advancing the technologies during the early 1980s.[46] Elimination or reduction in the size of the tax incentives—or even the possibility of such changes—is likely to slow deployment.

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[43] Vasel Roberts, "Utility Preface," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, p. v.

[44] Vane E. Suter, "Who Will Develop the Governmental Resources?" *Proceedings: Seventh Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI AP-3271, pp. 7-10 through 7-13; and Vasel W. Roberts, "EPRI Geothermal Power Systems Research Program," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, pp. 4-1 through 4-3.

[45] Vasel Roberts and Paul Kruger, "Utility Industry Estimates of Geothermal Energy," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, p. 4-27 through 4-31.

Important too will be other government activities at the Federal, State, and local levels. The level of direct support for R&D will continue to be a key determinant of technical progress in the industry. Also influential will be the many forms of regulatory control government agencies exert over the activities required to deploy geothermal technologies. Because of the importance of government, and the number and diversity of relevant agencies, the degree to which their activities are coordinated will be equally important.[47]

Other factors that may impede the deployment of geothermal technologies in the 1990s include:

Equipment Cost and Performance.—As discussed in chapter 4, dual-flash and binary-cycle technologies are relatively immature. Cost reductions and performance improvements in some cases may be necessary, not only with the equipment used in actually producing the electric power, but in some cases also in the technology required to deliver brine to the surface. The rate at which progress occurs depends strongly on the amount of capital devoted to R&D.

Three factors may retard R&D investment. First, the members of the geothermal industry most capable of shouldering R&D investments—those affiliated with the petroleum companies—may not invest the necessary capital,[48] partly because of the current soft petroleum market. Second, activity in the geothermal industry is affected heavily by nonutilities, whose investment levels are influenced strongly by State and Federal tax policies. Possible changes in the policies, the most immediate of which is the expiration of the Federal renewable energy tax credit, will greatly diminish geothermal investment. Third, the Federal Government, which historically has been the major source of R&D funds, has sharply cut its support (see table 9-2).

Technology Demonstration.—Beyond the geothermal demonstration plants already being built or operating, very little additional capacity is planned with the developing geothermal technologies. Should few additional plants be deployed in the next 5 to 10 years, the lack of extensive commercial experience is likely to impede rapid expansion of capacity in the 1990s, since the associated risks may be perceived as too high. Difficulties in gaining access to adequate information on cost and performance could also slow timely deployment of developing geothermal technologies in the 1990s.[49]

Geothermal Exploration, Resource Identification and Assessment.—Once a geothermal resource is discovered, more precise information on the quality of the resource is needed in order to assess the economics of site development and to optimize plant design. This requires that resource qualities be measured further and the information analyzed. The lack of site measurements and adequate analytical capabilities are considered major impediments to the development of geothermal power.

Federal Leasing Requirements.—A considerable portion of the geothermal resource in the United States lies under Federal lands. The leasing of this land, administered by the Bureau of Land Management, is characterized by two requirements which may impede deployment of geothermal technologies. First, no single leaseholder may hold leases covering more than 20,480 acres in any specific State.[50] This reportedly has slowed the rate at which resources can be assessed and at which development can occur. Second, primary lease terms are for 10 years; a leaseholder must develop the land within that period or lose the lease. This may inhibit commitments to develop particular geothermal resources.[51]

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[46] Subcommittee on Energy and Mineral Resources, Senate Committee on Energy and Natural Resources, U.S. Congress, *Geothermal Energy Development in Nevada's Great Basin: Hearing to Examine the Current Status and Future Needs of Nevada's Geothermal Energy Industry* (Washington, DC: U.S. Government Printing Office, 1984) Sparks, Nevada, April 17, 1984, S.Hrg. 98-801.

[47] Alex Sifford, *Background Geothermal Information for the 1985 Energy Plan* (Salem, OR: Oregon Department of Energy, February 1985), mimeo, and James Ward, "Geothermal Electricity in California," Transitions to Alternative Energy Systems—Entrepreneurs, New Technologies, and Social Change, Thomas Baumgartner and Tom R. Burns (eds.) (Boulder, CO: Westview Press, 1984), pp. 167-186.

[48] See, for example, Chris B. Amundsen, et al., *A Summary of U.S. Department of Energy Geothermal Research and Development Program Accomplishments, Industry Response, and Projected Impact on Resource Development* (Philadelphia, PA: Technecon Analytic Research, Inc., 1983).

[49] U.S. Department of Energy, *Geothermal Progress Monitor* (Washington, DC: DOE, 1983), Report No. 8; and testimony of Jon Wellinghoff (Consumer Advocate, State of Nevada), p. 5 in Subcommittee on Energy and Mineral Resources, *Geothermal Energy Development in Nevada's Great Basin: Hearing to Examine the Current Status and Future Needs of Nevada's Geothermal Energy Industry*, op. cit., 1984.

[50] The 1970 Geothermal Steam Act, however, does allow the Secretary of Interior to raise the statewide acreage limitation after Dec. 24, 1985. Indeed, in April 1985, the Department of the Interior proposed that the limitation be raised to 51 200 acres.

Utility Energy and Capacity Credits, and Interconnection Requirements.—As with the other technologies discussed so far in this chapter low energy credits, low capacity payments, and stringent interconnection requirements discourage deployment by nonutilities. Even where the *possibility* exists that credits could drop during the lifetime of a project, investment is discouraged. Also, any difficulties (such as delays) encountered in seeking to obtain favorable credits or interconnection requirements discourages nonutility deployment.[52]

Transmission Capacity.—Like wind resources, geothermal resources often are located in areas which are not readily accessible or located near transmission facilities. Moreover, in some cases, the geothermal resources are far from the markets offering the highest avoided costs. The lack of adequate transmission facilities connecting the resources with markets and/or institutional mechanisms for wheeling power to these markets is considered a major impediment to the further deployment of geothermal technologies of any kind, especially in Oregon and Nevada.[53]

Leasing, Permitting, and Licensing Delays.—Where geothermal development is planned on Federal property, considerable delays may be occasioned in securing the necessary lease. Further delays also may result as the requisite licenses and permits are obtained from various public agencies.[54] Problems regarding water consumption and subsidence in particular may occasion delays, particularly in agricultural areas.[55] Together, these time-consuming steps may limit the amount of capacity which could be deployed in the 1990s.

Fuel Cells

History and Description of the Industry

The current major efforts to develop the fuel cell for grid-connected applications in the United States are split between natural gas and electric utilities. The electric utilities are pursuing the use of fuel cells in central station applications, while gas utilities have concentrated on relatively small, "onsite" fuel cells which would increase markets for natural gas.

As with photovoltaics, the initial commercial impetus behind fuel cell development in the United States was the space program in the 1950s and 1960s. Efforts to develop fuel cells for terrestrial applications multiplied during the mid-1960s, but by the end of the decade most had ceased with one notable exception. In 1967 a group of gas utilities formed an organization[56] to develop equipment that somehow could counter the electric power industry's capture of the gas industry's markets. This and subsequent programs culminated in the current effort in which the Gas Research Institute (GRI), funded by the gas industry, and DOE are deploying and testing forty-six 40 kWe fuel cell cogeneration units. Several units of this size also were installed in Japan. Concurrently, GRI and DOE are funding a coordinated multi-year research project expected to yield an "early entry" onsite fuel cell system with an expected output of about 200 to 400 kWe.

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[51] See: 1) J. Laszlo, "Findings of U.S. Senate Hearings on Geothermal Development in Nevada," *Proceedings: Eighth Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3686, p. 6-16 through 6-20; 2) Vane E. Suter, "Who Will Develop the Governmental Resources?" *Proceedings: Seventh Annual Geothermal Conference and Workshop*, op. cit., 1983; 3) Subcommittee on Energy and Mineral Resources, *Geothermal Energy Development in Nevada's Great Basin: Hearing to Examine the Current Status and Future Needs of Nevada's Geothermal Energy Industry*, op. cit., 1984; 4) Subcommittee on Energy and Mineral Resources, Senate Committee on Energy and Natural Resources, U.S. Congress, *Geothermal Steam Act Amendments of 1983* (Washington, DC: U.S. Government Printing Office, 1983), Hearing, May 2, 1983, S.Hrg. 98-392; and 5) James Ward, "Geothermal Electricity in California," *Transitions to Alternative Energy Systems—Entrepreneurs, New Technologies, and Social Change*, op. cit., 1984).

[52] See J. Laszlo, "Findings of U.S. Senate Hearings on Geothermal Development in Nevada," op. cit., 1984, and Subcommittee on Energy and Mineral Resources, *Geothermal Energy Development in Nevada's Great Basin: Hearing to Examine the Current Status and Future Needs of Nevada's Geothermal Energy Industry*, op. cit., 1984.

[53] See: 1) J. Laszlo, "Findings of U.S. Senate Hearings on Geothermal Development in Nevada," op. cit., 1984; 2) C.J. Weinberg, "Role of Utilities, Resource Companies, and Government: Discussion Group Report," *Proceedings: Seventh Annual Geothermal Conference and Workshop*, Altas Corp. (ed.) (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI AP-3271, pp. 7-26 through 7-27; and 3) Subcommittee on Energy and Mineral Resources, *Geothermal Energy Development in Nevada's Great Basin: Hearing to Examine the Current Status and future Needs of Nevada's Geothermal Energy Industry*, op. cit., 1984.

[54] Included in the information required for facility licensing and permitting is baseline data on the environmental conditions at a site. For more information, see Alex Sifford, *Background Geothermal Information for the 1985 Energy Plan*, op. cit., 1985.

[55] For a discussion of the water issue in the Imperial Valley, where considerable deployment of dual-flash and binary systems may occur in the 1990s, and where agriculture is very important, see: Department of Public Works, Imperial County, *Water for Geothermal Development in Imperial County: A Summarizing Report* (El Centro, CA: Imperial County, June 1984), special report, DOE Cooperative Agreement DE-FC03-79ET27196.

Meanwhile, since 1971, fuel cell manufacturers, electric utilities,[57] the Electric Power Research Institute, the Federal Government and others have sought to develop and deploy multi-megawatt fuel cell power facilities. By 1978, a 4.5 MWe project was initiated in New York City. The New York unit suffered from delays in gaining local regulatory approval. These delays exceeded the storage life of the power section so that the unit could not be operated without refurbishment. As a result, the project was abandoned in 1984. Another similar, but improved unit was installed in Japan. That unit, made by the same manufacturer which produced the New York installation, has operated very successfully since April 1983. Currently, plans are being laid both in the United States and in Japan to first develop and deploy commercial demonstration units, and then to initiate commercial production of fuel cells late in the 1980s or early 1990s.

In the recent years a number of cooperative agreements between Japanese and U.S. firms have evolved, perhaps the most important of which is the joint venture between United Technologies and Toshiba. The two companies have agreed to cooperative electric utility commercial powerplant design and development activity. This alliance may lead to an agreement to construct a fuel cell production facility in the United States sometime in the near future.[58] The substantial capital and technological capabilities of these corporations enhance the prospects that the hurdles faced in early commercialization may be successfully and readily overcome.

Government involvement on both sides of the Pacific has been extensive. In the United States, Federal funding has been divided between military/space applications and support of civilian commercial uses. The support for civilian applications has emphasized the use of fuel cells in transportation and in electric power generation; this support has emanated from DOE and its predecessor agencies. The DOE program of greatest importance to the near-term commercial prospects of the fuel cell is the Phosphoric Acid Fuel Cell Program. The National Aeronautics, and Space Administration (NASA)-Lewis Research Center has been designated by DOE as the lead center for the program.

DOE's funding for fuel cells is summarized in table 9-2. DOE's support peaked in 1984, when $42.3 million were spent on the technology. A very substantial portion of the funds has been dedicated to the phosphoric acid technology—which is the most promising technology for initial commercial penetration. While DOE spending on fuel cells dropped only slightly in fiscal year 1985, a substantial reduction to $9.3 million has been proposed for 1986. Under the latter proposal, support for the phosphoric acid technology is eliminated altogether.[59]

Although some fuel cell research and development took place in Japan during the 1960s and 1970s, the current Japanese fuel cell program did not materialize until 1981. At that time, under the aegis of the Ministry of International Trade and Industry (MITI), the agency's "Moonlight Project" initiated a coordinated program directed towards the development of fuel cell technologies for various applications. All of the Japanese equipment manufacturers are working under this program, as are several Japanese utilities.

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[56] The Team to Advance Research on Gas Energy Transformation (TARGET).

[57] Electric utility efforts in support of the fuel cell have been mediated in part through the Electric Utility Fuel Cell Users Group, an association established about 5 years ago. The group, now consisting of over 60 members, works closely with EPRI, fuel cell vendors and others to promote the use of fuel cells among electric utilities. For more information, see "Fuel Cell Users Group," *EPRI Journal*, vol. 10, No. 1, January/February 1985, pp. 62-63.

[58] P.J. Farris, Business Planning Staff, International Fuel Cells (unpublished memorandum for OTA staff), June 18, 1985. For more information on these U.S.-Japanese efforts, see: Peter Hunt Associates, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells* (Alexandria, VA: Peter Hunt Associates, 1984), OTA contractor report.

[59] See Herbert Lundblad and Ronald R. Cavagrotti, *Assessment of the Environmental Aspects of DOE Phosphoric Acid Fuel-Cell Program* (Cleveland, OH: Lewis Research Center, 1983), DOE/NASA—2703-3, pp. 7-20; and Fred Sissine, *Fuel Cells for Electric Power Production: Future Potential, Federal Role and Policy Options* (Washington, DC: Congressional Research Service, 1985).

While the Japanese have in the past lagged behind the U.S. program, it appears that the current Japanese program has narrowed the gap. This results in part from the attentive observation of and participation in U.S. efforts. The Japanese have learned from U.S. successes and mistakes, while providing their own refinements and modifications.

Industry Outlook and Major Impediments

The fuel cell industries in both the United States and Japan are positioning themselves for substantial commercial deployment of fuel cells in the 1990s. At the cost and performance levels which the fuel cells may achieve, extensive markets for both central station and dispersed applications could develop.

Deployment in Japan, fostered by the government (MITI), could be quite rapid. Particularly important in this regard is the close working relationship the Japanese fuel cell developers have with the country's electric power companies. This will ease the difficulties the manufacturers might encounter in the early stages of commercial transition. Over the next 15 years the well-coordinated Japanese effort probably will place that country's fuel cell manufacturers in a position comparable or perhaps superior to their U.S. counterparts barring significant increases in this country's efforts.[60] In Japan, fuel cells using primarily imported natural gas are expected to provide a few percentage points of total generating capacity by 1995, and could provide 7 to 8 percent of generating capacity at the beginning of the 21st century.[61]

The rate at which fuel cells are deployed in the United States probably will be slow at first, until confidence among potential investors is built up. The length of this transitional period is a matter of speculation. It is likely that the first commercial units will not be erected until investors are convinced these early commercial systems will operate well. Since both the small (200 to 400 kWe) and large (multi-megawatt) demonstration units will not be installed until the latter part of the 1980s, operating experience sufficient to justify initial commercial orders probably will not develop until the beginning of the next decade. It is likely that the proposed termination of Federal funding of phosphoric acid fuel cell development will slow this process and perhaps weaken the industry's competitive status with the Japanese; but it is not clear how serious the effect will be.[62]

The potential market in the United States is very large. An EPRI study of the potential utility market suggests that fuel cells could provide as much as 65,000 MWe of generating capacity by 2005.[63] At the same time, circumstances favor nonutility development too. Substantial advantages are associated with dispersed cogeneration applications under nonutility ownership. Investors, led by the gas utilities and perhaps the fuel cell manufacturers themselves, could stimulate rapid growth in nonutility applications in the 1990s.[64]

By the mid-1990s, total experience around the country and in Japan could be sufficient to trigger rapid growth in the technology in the late 1990s. With very favorable conditions, this growth could occur even sooner. Various impediments, however, could delay extensive commercial deployment until after the close of the century. These impediments are listed below.

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[60] Ernest Raia, "Fuel Cells Spark Utilities' Interest," *High Technology*, vol. 4, No. 12, December 1984, pp. 52-57.

[61] N. Horiuchi et al., "Applications of Fuel Cell Power Plants in Japanese Utility Use," *1983 National Fuel Cell Seminar: Program and Abstracts* (Washington, DC: Courtesy Associates, Inc., 1984), Orlando, FL, Nov. 13-16, 1983, pp. 173-176.

[62] Robert L. Civiak, et al., *Impacts of Proposed Budget Cuts in Selected Energy Research and Development Programs* (Washington, DC: Congressional Research Service, 1985).

[63] Electric Power Research Institute (EPRI), *Application of Fuel Cells on Utility Systems: Study Results* (Palo Alto, CA: EPRI, 1983), vol. 1, EPRI EM-3205.

[64] Peter Hunt Associates, *Analysis of Equipment Manufacturers and Vendors in the Electric Power Industry for the 1990s as Related to Fuel Cells*, op. cit., 1984.; Peter B. Bos and Jerome M. Weingart, "Integrated Commercialization Analysis for New Power Generation Technologies," *Energy Technology XI, Applications and Economics: Proceedings of the Eleventh Energy Technology Conference, Mar. 19-21, 1984*, Richard F. Hill (ed.) (Rockville, MD: Government Institutes, Inc., August 1984), pp 188-205; and "Industrial, Commercial Sites Eye Fuel Cells," *Coal Technology Report*, Jan. 23, 1984, p. 2.

Equipment Cost and Performance.—As was discussed in chapter 4, current evidence suggests that it is possible to mass produce fuel cells, to sell them at acceptable prices, and to operate them without excessive problems. However, this is by no means certain. Demonstration plants are necessary to reduce the uncertainty to a level more acceptable to investors. Further research and development, aimed at incremental improvements in the equipment, would increase the possibility that cost and performance will fall within the necessary ranges in the 1990s.

Perhaps the most important impediment facing the fuel cell is the lack of an initial market sufficient to justify mass-production. Without a sizable initial market, only small numbers of relatively expensive fuel cells can be manufactured. These must be sold at high prices—thereby inhibiting demand—or the manufacturer must, in the short term, operate at a loss. The time it takes to overcome this problem will, perhaps more than any other factor, determine the rate of commercial application of fuel cells in the 1990s.

Technology Demonstration.—The successful demonstration of both small and large fuel cells will be of critical importance to stimulating investment in the technology. Demonstration units will be needed to encourage the initial round of orders.

Utility Energy and Capacity Credits, and Interconnection Requirements.—As mentioned above, a major market for fuel cells lies outside the electric utilities. Like other grid-connected, nonutility applications initiated under PURPA, low energy credits, low capacity payments, and stringent interconnection requirements discourage deployment by nonutilities. Even where the *possibility* exists that credits could drop during the lifetime of a project, investment is discouraged. Also, any difficulties (such as delays) encountered in seeking to obtain favorable credits or interconnection requirements discourages nonutility deployment.

Licensing and Permitting Delays.—In the long term, licensing and permitting delays are likely to be minimized by virtue of the technology's relatively low environmental impacts. However, other circumstances might lengthen delays. The technology will in many instances be installed in areas where powerplants have not been traditionally sited and in highly populated areas where safety considerations are likely to be heavily emphasized. Moreover, the technology is new and regulatory officials are not well acquainted with it. The 4.5 MWe facility which was installed in New York was the subject of many unexpected delays; similar problems could develop with future plants.

Integrated Gasification/Combined-Cycle Plants

History and Description of the Industry

The integrated gasification/combined-cycle plant (IGCC) is a relatively new combination of components—gasifiers, gas turbines, and steam turbines—which themselves have been around in some form for a long time. Steam turbines have been used to generate electrical power since 1930 in the United States, and now are used to generate more electrical power worldwide than any other technology.[65]

Gas turbines were not used for commercial generation of electric power in the United States until 1961. Spurred by the need for fast-starting generating capacity and encouraged by the short lead-times typical of gas turbines, utilities in the 1960s and early 1970s deployed many of these units.[66]

Coal gasifiers were being used commercially by the early 1800s. By 1930, there were about 11,000 coal gasifiers in the United States. These were used to produce gas for both light and heat in cities as well as for industrial uses. From the 1930s through the mid-1950s, development continued, especially in Germany and the United States. The basic design of large commercial gasifiers which today form the basis for IGCC developments originated during this period.[67]

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[65] Based on telephone conversation between Bruce W. Morrison, V.P. Atlantic Region, Westinghouse Electric Corp., and OTA staff, May 16, 1985.

[66] Ibid.

With the availability in the United States of low cost, reliable supplies of natural gas in the late 1950s and the 1960s, activity involving coal gasification in the United States was maintained at only a very low level, though it continued to be important in the steel industry. Greater interest continued overseas, however, where circumstances favored the technology's development.

The 1970s brought renewed interest in gasification for various applications, including electricity generation. The use of coal gasifiers in electricity generation offered some important advantages. It allowed for greater reliance on domestic coal resources, less dependence on oil or gas, and its environmental impacts were less severe than those of more conventional coal-fired equipment. In addition, coupling a coal gasifier to a combined-cycle system appeared to meet the growing demand for highly efficient generation.

But the economic use of gasifiers in electricity production required technical improvements over earlier commercial technologies. In response to this need, advanced gasifiers have been developed. Several prime candidates for application in IGCC systems for the 1990s have emerged; these gasifiers have either been used commercially in some application, or are in advanced stages of development. Each has specific advantages and disadvantages. The principal corporations developing gasifiers included Texaco, Inc., Shell, the Allis Chalmers Corp., Dow Chemical, the British Gas Corp. (BGC), Kellog Rust (the KRW gasifier), and Lurgi Gesellschaften. The latter two corporations have cooperated in the development of a single gasifier design known as the BGC/Lurgi gasifier.

The current status of gasification systems being developed by these corporations is summarized in table 9-4. Activities directed towards the development and commercial deployment of the gasifiers have not been directed just to IGCCs but to a considerably broader range of applications.

Among the major gasifier systems which had operated in nonelectric applications in the United States by mid-1985 were the Illinois Power Co.'s Wood River facility, which used a KILnGAS gasifier developed by the Allis Chalmers Corp. primarily for IGCC applications; and Tennessee Eastman Co.'s gasification plant in Kingsport, Tennessee, which used Texaco gasifiers. Other important gasification plants have been operated by the Tennessee Valley Authority; and by the Great Plains Gasification Associates in Beulah, North Dakota. Many of these projects have received Federal support through DOE or the Synthetic Fuels Corp. Coal gasification meanwhile has been pursued overseas as well.

Only one type of gasifier, developed by Texaco, had by mid-1985 been deployed in an IGCC installation in the United States—the Cool Water Project, the world's first demonstration of an IGCC using commercial-scale components. Conceptual studies and other activities concerning this plant began in the mid-1970s and in 1979 Southern California Edison and Texaco signed an agreement which formally initiated the project.

The effort later was joined by EPRI, Bechtel Power Corp., the Japan Cool Water Program Partnership, the Empire State Electric Energy Research Corp. (a group of New York State utilities), SOHIO, and General Electric. Sizable loans were provided by banks in the United States and Japan. EPRI has made the greatest funding contribution to the program.

As the project progressed, oil prices dropped. Avoided costs, the basis for the purchase price of power produced by the plant, consequently would not be as high as was originally anticipated by the project sponsors. They were compelled to obtain price support guarantees from the Synthetic Fuels Corp. These amounted to a maximum of $120 million, to be provided during the plant's demonstration period, running through June 1989.[68]

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[67] Synthetic Fuels Associates, Inc., *Coal Gasification Systems: A Guide to Status, Applications, and Economics* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI AP-3109.

[68] Paul Rothberg, *Synthetic Fuels Corp. and National Synfuels Policy* (Washington, DC: Congressional Research Service, 1984), Issue Brief Number IB81139.

Table 9-4.—Status of Developing Gasification Technologies

Process	Value of technology for electric power production	Number of units in design, construction, or operation in June 1985			
		Small pilot units (< 50 t/d)	Large pilot units (100-300 t/d)	IGCC units (demonstration/commercial) (>600 t/d)	Other large-scale demonstration or commercial units
Texaco	High	$\boxed{2}$ • Texaco (Montebello) (2 gasifiers)	$\boxed{2}$ • Ruhrkohle/Ruhrchemie Oberhausen (1 gasifier) • TVA-Muscle Shoals (1 gasifier)	$\boxed{2}$ • Cool Water (2 gasifiers)	$\boxed{9}$ • Tennessee Eastman (2 gasifiers) • UBe Ammonia (4 gasifiers) • Ruhrkole/Ruhrchemie (1 gasifier) • Lunan (China) (2 gasifiers)
BGC/Lurgi	High	$\boxed{1}$ • British Gas (Midlands) (1 gasifier)	$\boxed{1}$ • British Gas (Westfield) (1 gasifier)	$\boxed{4}$ • Detroit Edison/Consumers Power (4 gasifiers)	$\boxed{1}$ • British Gas (Westfield) (1 gasifier)
Shell	High	$\boxed{1}$ • Shell (Amsterdam) (1 gasifier)	$\boxed{2}$ • Shell (Harburg) (1 gasifier) • Shell (Deer Park) (1 gasifier)	• Northeast Utilities (1 gasifier)	
Dow	High	$\boxed{2}$ • Dow (Freeport) (1 gasifier) • Dow (Plaquemine) (1 gasifier)	$\boxed{1}$ • Dow (Plaquemine) (larger than 300 t/d) (1 gasifier)	$\boxed{1}$ • Dowsyn (Plaquemine) (1 gasifier)	
KRW (Westinghouse)	Moderate-high	$\boxed{1}$ • Westinghouse (Waltz Mill) (1 gasifier)		$\boxed{2}$ • Keystone (Johnston, PA) (2 gasifiers)	$\boxed{1}$ China (1 gasifier)
Allis-Chalmers	Moderate	$\boxed{1}$ • A-C (Oak Creek) (1 gasifier)			$\boxed{1}$ KILnGAS (Wood River) (1 gasifier)

☐ Represents total number of gasifiers within any category

SOURCE: M. Gluckman, Electric Power Research Institute, personal communication, June 1985

Another IGCC unit soon will be under construction in Plaquemine, Louisiana. Designed by Dow Chemical, the plant is expected to begin operating in 1987 with a substantial contribution from the Synthetic Fuels Corp.—$620 million in price guarantees. Most recently, three U. S. utilities—the Potomac Electric Power Co., the Virginia Electric Power Co., and the Detroit Edison Co.—have initiated the steps which could lead to the deployment of three IGCC units during the 1990s.[69]

As suggested above, the development of gasification technologies has generally depended heavily on Federal support through the Synthetic Fuels Corp. In addition the Federal Government has supported the development of gasification through DOE and its predecessor agencies. Most of this DOE support has been for research, development, and demonstration of surface coal gasification.[70] As indicated in table 9-2, this support peaked in 1978 at $208 million and has declined since to a proposed $15 million for fiscal year 1986.

Efforts in the private sector on behalf of the IGCC have emanated mainly from the equipment developers in the private sector, interested utilities and EPRI. The vendors of both the turbines and the gasifiers are large corporations which have funneled considerable capital into the research, development, and demonstration of their products. While the investments sometimes are directed primarily toward the application of the equipment to the IGCC (as was the case at the Cool Water Plant), they usually are intended to advance the technologies over a wider variety of applications.

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[69] For details on Potomac Electric Power Co.'s (PEPCO) plans, see: Steven M. Scherer, "PEPCO's Early Planning for a Phased Coal Gasification Combined Cycle Power Plant," paper presented at the EPRI and Kernforschungsanlage Julich Conference on Coal Gasification and Synthetic Fuels for Power Generation, San Francisco, CA, April 1985.

[70] Surface coal gasification is distinct from underground coal gasification. The latter involves technologies which are very different from those considered here and are not candidates for IGCC systems in the 1990s.

EPRI has devoted a large portion of its budget towards the development of the IGCC, both through numerous studies and through its funding of the Cool Water Plant. EPRI also parented the Utility Coal Gasification Association (UCGA), a group of utilities interested in the IGCC. Formed by early 1983, the association collected and disseminated information on the technology and its applications, and otherwise encouraged its deployment. The early commercial users of the IGCC probably will be among the association's members.

In addition to participation in the UCGA, some utilities have been considerably more involved in the technology. Southern California Edison, for example, invested heavily in the Cool Water project and has been very active in promoting the IGCC.

Industry Outlook and Major Impediments

Three primary criteria must be met if the IGCC is to make a sizable contribution to generating capacity in the 1990s. First, a number of utilities must be convinced the technology will perform as required over its entire 30-year lifetime. Second, the combination of cost, performance, and risk will have to be superior to that of both conventional and other developing technologies—including atmospheric fluidized-bed combustion (AFBC). Third, projects probably must be initiated no later than late 1993 if they are to come online within the 1990s.

Taken together, these elements suggest that additional utilities indeed may step forward over the next 3 to 8 years and initiate IGCC plants. However, the current evidence suggests other factors--the most important of which are discussed below—may weigh against initiation of many projects during the short time available. Consequently, there is a possibility that only a few—perhaps a half-dozen or less—IGCCs will be operating in the United States by the end of the century.

Equipment Cost and Performance.—Many of the individual components of the IGCC have been commercially applied for many years. Among available components is equipment which either already is adequate for IGCC applications or probably will be in the near future. Other components, though, are relatively new and in fact may be unique to the IGCC. Evidence from the Cool Water plant experience to date and from other sources indicates that these components will perform adequately and will not involve excessive cost. However, experience with IGCCs is still limited, and while the Cool Water performance has been very good, many utility investors may still lack sufficient confidence in component cost and performance estimates. Consequently, even if cost reductions or performance improvements are not in fact necessary, uncertainty about equipment cost and performance may be a serious impediment to timely investment.

Cost and Performance Data/Technology Demonstration.—An important concern about the IGCC in the eyes of investors over the next 5 to 7 years will be the lack of demonstrated experience with the entire system, and hence the lack of proven integrated cost and performance data. The Cool Water plant and the Dow facility probably will be the only IGCCs to which investors may turn for a reference point. It is perhaps for this reason that an EPRI official in mid-1984 told a congressional subcommittee that the deployment of at least one or two additional IGCC demonstrations in the United States, using perhaps the BGC or Shell gasifiers, was a very high priority in promoting clean coal utilization in the 1990s.[71] Others too have cited the need for further demonstrations.[72]

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[71] Dwain Spencer, Electric Power Research Institute, testimony presented in hearings held by the Subcommittee on Energy Development and Applications, House Committee on Science and Technology, U.S. Congress, *The Status of Synthetic Fuels and Cost-Shared Energy R&D Facilities* (Washington, DC: U.S. Government Printing Office), No. 106, June 6, 7, and 13, 1984, p. 203.

[72] See: 1) "Firms Plan CGCC Plant in Michigan," *Synfuels Week*, vol. 6, No. 13, Apr. 1, 1985, p. 1. 2) "Va. Power Plans 400 MW CGCC Plant," *Synfuels Week*, vol. 6, No. 12, Mar. 25, 1985, pp. 1-2. This article discusses the plans of Virginia Power Corp. to "repower" an existing powerplant with a gasification system, and a combined-cycle system to form a "coal gasification/combined cycle" unit or CGCC. The utility has proposed that the Federal Government subsidize the project. It reported that even without Fed-

Utilities, of course, will examine their own experiences and those of others with gas turbines, steam turbines, and combined-cycles, and will scrutinize gasifiers operating both here and abroad in nonelectric applications. The favorable experience with those components certainly will help to reduce the risks perceived by investors, but they are unlikely to fully offset the lack of experience with the IGCC itself.

Note that as experience with the Cool Water plant accumulates, experience with AFBCs will be accumulating much more rapidly as both demonstration and commercial plants come online under both utility and nonutility ownership and under different operating conditions. It is likely that the AFBC, with its larger number of operating plants and its favorable cost and performance, will pose a formidable challenge to the IGCC for initial utility commitments.

Licensing and Permitting Delays.—A major source of delay for IGCCs could lie in the licensing and permitting process. Though the environmental impacts of the IGCC will be less severe than those of its conventional competitors, it nevertheless does have significant impacts on the environment. Concern over the impacts could result in delays, particularly if the potential environmental impacts are not precisely known by regulators, or where important regulatory issues regarding the technology have not been satisfactorily resolved.

For example, very little data are available on the long-term leaching characteristics of gasification ash/slag. Furthermore, the analytical tools necessary to adequately determine the possible impacts of the solid waste in a specific environment, and to properly develop or assess measures to mitigate those impacts, are lacking. Yet such data and methods are required to properly determine whether or not the solid waste should be treated as hazardous or nonhazardous, and in evaluating specific plant proposals.[73]

Certainly measures can be taken by government authorities to expedite the IGCC's progress through regulatory channels.[74] Regulatory bodies may provide an IGCC technology with special treatment, as was the case in California with the Cool Water project. Under such circumstances, delays may be reduced substantially. More importantly, constructors of initial plants can work closely with regulatory bodies to ensure efficient resolution of potential concerns. If either of these paths are followed, the amount of IGCC capacity by the year 2000 could be substantially higher than would otherwise be the case. If such is not the rule, however, delays could result because of the newness of the technology that could seriously impede the ability of project promoters to bring IGCCs on-line before the end of the century.

Stringency of Environmental Regulations.—A major advantage of the IGCC over its conventional competitors is its potential to operate with lower nitrogen oxide and sulfur oxide emissions, at incremental costs lower than those associated with equivalent emission reductions in a conventional coal plant. Where emissions are severely limited, the IGCC is able to capitalize on this advantage. Where such limitations are lacking, however, the IGCC is less able to successfully compete with the more conventional alternatives. The lack of stricter regulations which require lower emissions consequently may reduce incen-

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eral support, it would install the combined-cycle portion of the plant and operate it beginning in 1993. But the gasification portion of the project would be delayed without Government support: the system would employ natural gas instead of gas produced from coal. Referring to the gasification portion of the system, officials of the utility reportedly stated that "the technology is unproven and the utility decided that privately financing its early introduction in the marketplace would be 'an unreasonable risk to (Virginia Power) ratepayers and stockholders.' " A company official was quoted as saying: "We are a risk averse industry. Without some Government help to defray the risk, our implementation of the gasification technology would just have to wait." According to the utility, without Government assistance, the "conversion to coal gasification could be subsequently pursued when the technology and economics become favorable about ten years later or 2003."

[73] Masood Ghassemi and George Richard, "Regulatory Requirements for Land Disposal of Coal Gasification Waste and Their Implications for Disposal Site Design," *Energy Sources*, vol. 7, No. 4, 1984, pp. 357-376. The authors state that ". . . environmental issues involving disposal of these wastes may constrain the commercial development of gas supply technologies" (p. 358).

[74] See: 1) Masood Ghassemi and George Richard, "Regulatory Requirements for Land Disposal of Coal Gasification Waste and Their Implications for Disposal Site Design," op. cit., 1984. 2) Arturo Gandara, "Environmental Considerations in Siting Alternative Fuel Generating Facilities," *California Energy Commission News and Comment*, No. 13, spring 1984, pp. 4-18 (reprint of testimony presented to the Advisory Committee on Federal Assistance on Alternative Fuels, Oct. 31, 1983).

tives to more extensive deployment of IGCCs in the 1990s.

Fuel Use Restrictions.—An IGCC plant typically will require access to natural gas. If the installation is built in stages, the gas turbines can be installed first and can use natural gas as an interim fuel until the gasifiers are completed. Also, natural gas can be used during the lifetime of the plant to replace or supplement the synthetic gas produced by the gasifiers. As explained earlier, the Fuel Use Act prohibits the use of natural gas under certain conditions. An exemption would be required from the Federal Government which would permit the use of natural gas in an IGCC. This could cause delays in a project, and denial of an exemption may even lead to project abandonment.

Atmospheric Fluidized-Bed Combustors

History and Description of the Industry

In the early 1920s, fluidized beds were applied for the first time in Germany to produce combustible gases from coal. Subsequent development led to their use in "cracking" the heavy fractions of petroleum, first in 1942 and extensively thereafter. Further efforts led to their application to other industrial uses and eventually to produce steam. The first commercial fluidized-bed boiler began operation in France in 1955. Serious development of fluidized-bed boilers did not begin in the United States until 1965.[75]

By 1976, DOE was funding the construction of the first industrial-sized AFBC boiler in the United States—a 30 MWe pilot plant in Rivesville, West Virginia. Several more small industrial AFBCs were built in the late 1970s and early 1980s as the technology progressed rapidly and small AFBCs became competitive with conventional options in the marketplace. Coincident with the emergence of small AFBCs during this period was the implementation of PURPA, which set the stage for a rapid increase in the deployment of AFBCs in cogeneration applications.

By early 1985, over 2,200 AFBCs were operating in China, and between 200 and 300 were operating or under construction elsewhere in the world, mostly in Western Europe, Japan, and the United States. Most of those outside China were small industrial units. Over 40 small AFBCs were operating or under construction in the United States by early 1985, and by mid-1985, over a dozen privately financed commercial AFBC cogenerators were being built in the United States. Unit sizes of these U.S. plants range from 15 to 125 MWe; none of these fully commercial units is owned by an electric utility.[76]

The electric utilities are, however, showing a growing interest in the technology. The thrust of utility-sponsored R&D has been the development of AFBCs with capacities in excess of 100 MWe for retrofit to existing powerplants or for entirely new plants. Toward this end, three demonstration projects are currently under construction. Two are retrofit units being incorporated into existing plants.[77] The third is a 160 MWe demonstration unit at the Tennessee Valley Authority's (TVA) Shawnee Steam Plant in Paducah, Kentucky. The retrofit units will begin operating in 1 to 2 years; the TVA unit is expected to be fired first in 1989.

Central to the utility efforts has been the Electric Power Research Institute. By 1977, EPRI had built a 2 MWe pilot plant. This was followed by a 20 MWe plant which began operation in 1982. EPRI now is partly funding all three of the above mentioned demonstration projects.

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[75] Shelton Ehrlich, "History of the Development of the Fluidized-Bed Boiler," *Proceedings of the 4th International Conference on Fluidized-Bed Combustion, Dec. 9-11, 1975* (McLean, VA: MITRE Corp., May 1976), Publication M76-36, pp. 15-20; and A.M. Squires, "Contributions Toward a History of Fluidization," *Proceedings of the Joint Meeting of the American Institute of Chemical Engineers and the Chemical Industry and Engineering Society of China, Sept. 20-22, 1982* (New York: American Institute of Chemical Engineers, 1983), pp. 322-353.

[76] For a comprehensive review of the current status of AFBC's, see: Bob Schwieger, "Fluidized-Bed Boilers Achieve Commercial Status Worldwide," *Power*, vol. 129, No. 2, February 1985, pp. S-1 through S-16.

[77] These are the Colorado Ute 100 MWe Nucla unit, scheduled to begin operating in 1987; and the Northern States Power Co.'s 125 MWe Black Dog Unit 2, expected to be in operations in 1986. Note that one small retrofit unit already has operated. This is the Northern States Power Co.'s French Island Plant, Unit #2. The 15 MWe retrofit began operation in 1981.

The Federal Government too has supported the technology with a program which first led to the construction of the Rivesville plant in 1976 and subsequently to a series of pilot and demonstration facilities. Federal support peaked in 1980 at almost $30 million and has dropped sharply since. By far the largest portion of Federal funding for the AFBC now is channeled into the TVA 160 MWe demonstration plant—$30 million of the $220 million required for that project.

The industry which supplies AFBCs is large and well established. About 50 companies sell the industrial-sized boilers worldwide. Often, these are the same companies which sell conventional technologies. The adoption of the AFBC by these firms is likely to facilitate its deployment in the United States.

Industry Outlook and Major Impediments

Four applications of the AFBC may be important over the next 15 years: grass-roots electric-only plants, retrofit electric-only plants, cogeneration installations, and nonelectric systems. The electric-only units are likely to be deployed by utilities, whereas the cogeneration and nonelectric units probably would be built and operated by nonutility investors.

Current evidence suggests that the electric-only retrofit units, and cogeneration plants and nonelectric facilities financed by nonutilities may very well dominate the AFBC market in the 1990s. The rapid accumulation of operating experience with these units and their short lead-times—substantially shorter than those which would characterize large 100 to 160 MWe grass-roots, electric-only units[78]—makes their near-term prospects very bright.

The small AFBCs are being deployed extensively and many are expected to be initiated over the next decade. The market appears to be vigorous and growing, and suppliers abound. No barriers unique to these small units are expected to impede deployment, though some problems common to nonutility technologies—such as the adequacy of PURPA avoided cost payments—may develop.

A substantial utility retrofit market has also been identified; strong evidence indicates that numerous powerplants in the United States are candidates for AFBC retrofits. Most are small (less than 200 MWe), old units which are configured so as to allow a retrofit. Retrofit units probably will dominate early utility involvement with the AFBC. By the 1990s there will be more operating experience with retrofit units than with large grass-root units. Such retrofits appear to offer utilities a low cost option for improving existing capacity; they also require less time to deploy than the grass-roots plants. Commercial retrofits therefore could begin coming on-line before 1995, and large numbers may commence operating before the close of the century.

By the early 1990s, experience with the large utility demonstration units, expected to begin operating in the late 1980s, as well as experience with the smaller AFBCs outside the utility industry, may foster both technical improvements and utility confidence. The prospects appear to be good that extensive utility orders of large, commercial, grass-roots plants could begin at that time;[79] these plants could provide substantial amounts of electricity by the late 1990s. Delays of any kind, however, may limit the potential of AFBC grass-roots plants within this century. Such delays could be occasioned by problems or uncertainties associated with the performance of the larger AFBC units, or by difficulties in the licensing or permitting process.

Compressed Air Energy Storage

Industry Description, History, and Outlook

Major efforts in the United States on behalf of compressed air energy storage (CAES) began in the latter half of the 1970s, stimulated by the Federal Government, the Electric Power Research Institute, interested utilities, and others. Most important to these early efforts were three preliminary engineering-design studies, completed in 1981, which investigated the utility-specific application of CAES to the three major storage media (hardrock, salt, and aquifer CAES). Shortly before these studies were finished, in November 1980, the Soyland Power Cooperative, Inc., in Decatur, Illinois, formally committed itself to building the first U.S. CAES plant.

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[78] Retrofit units in many cases involve very little regulatory delay, as they are deployed at preexisting plants. Cogeneration units and nonelectric units commonly are very small, are not owned by utilities, and are not subject to the same extensive regulatory delays which characterize large utility owned projects.

[79] See Robert Smock, "Utilities Look to Fluid Bed as Next Step in Boiler Design," *Electric Light and Power*, vol. 62, No. 7, July 1984, pp. 27-29; and Taylor Moore, "Achieving the Promise of FBC," *EPRI Journal*, vol. 10, No. 1, January/February 1985, pp. 6-15.

As these events unfolded in the United States, the world's first CAES plant was built in Huntorf, West Germany; it began operating in December of 1978. Since that time, the 290 MWe Huntorf unit has operated nearly 7 years without serious problems. Furthermore, a smaller 25 MWe CAES unit recently was completed in Italy. Despite the successful operation of the German plant, the construction of the Italian plant, and efforts in the United States to deploy CAES plants here, this country still is without even a demonstration plant. The Soylands plant was canceled, and since then no U.S. utility has initiated construction of a CAES plant.

Federal support rapidly declined after peaking in 1978-79. Beginning with fiscal year 1983, DOE has provided no support to the technology (see table 9-2). Others, however, have continued promotional efforts. Although no CAES plants are now being constructed, EPRI and a private firm are currently performing an initial screening analysis of CAES on 10 utility systems. EPRI also is planning to provide funds in support of initial plant siting studies with interested utilities and in support of the installation of two or more 50 MWe "mini-CAES" plants.[80] Additionally, four consortia of architect/engineering firms, turbomachinery suppliers and cavern builders have been formed to supply initial plants.[81]

These developments suggest that several mini-CAES units could be initiated and built by the early 1990s. There are, however, no strong indications that a maxi-CAES plant (with a capacity of several hundred megawatts) will be initiated in the next several years and will be on-line within the first few years of the 1990s. Since a maxi-CAES plant will require a lead-time (including licensing and permitting) of approximately 5 to 8 years, plans to build any commercial maxi-CAES units must be underway no later than the end of 1994 for contribution to generating capacity within this century. Current evidence suggests that utility orders would be unlikely without a U.S. demonstration plant.

The prospects for mini-CAES plants in the United States appear to be much brighter. A mini-CAES plant requires a lead-time of approximately 4.5 to 6.5 years. If several are initiated by the end of 1986, they could be on-line by mid-1990. If extensive mini-CAES capacity is to be on-line by the year 2000, however, plans to build such plants should be initiated no later than mid-1990. This would allow approximately 5 years for the demonstration units to operate and for a substantial market demand to develop.

Such rapid growth in demand is possible, given the favorable levelized cost which might characterize CAES units (see chapter 8), and given the fact that many of the components are conventional and commercially available. Furthermore, the appropriate geology underlies 75 percent of the United States, so the market is potentially large and varied. EPRI estimates that CAES technology has the potential of supplying 4 to 8 percent of peak demand by the year 2000.[82]

To accomplish this will require that lead-times be kept short, and that other impediments be successfully cleared. The major impediments are discussed below. Unless these are effectively and speedily eliminated, demand is more likely to increase gradually, with large numbers of orders unlikely before the latter half of the 1990s.

Major Impediments to the Commercial Deployment of CAES Systems

The major impediments to *high* deployment levels for CAES by the end of the century are outlined below.

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[80] David Rigney, Electric Power Research Institute, "Notes on Compressed Air Energy Storage," provided to Brian E. Curry, Northeast Utilities, March 1985.

[81] Ibid.

[82] Robert B. Schainker, *Executive Overview: Compressed Air Energy Storage (CAES) Power Plants* (Palo Alto, CA: Electric Power Research Institute, August 1983), mimeo.

Uncertainty Regarding Plant Cost and Performance.—As discussed above and in chapter 4, while all of the individual above-ground components with the exception of the recuperative heat exchanger have been employed in other commercial applications, the performance of integrated assemblies coupled to specific geologic reservoirs is still unproven in the United States.

A principal area of concern is the impact of daily variations in pressure, humidity, and temperature on the reservoirs; these at present are not precisely known.[83] The prime concern is leakage of the air from the reservoir. Until one or more units have been installed and operated for at least several years, uncertainty will still trouble investors and is likely to strongly inhibit investment in CAES.

Licensing and Permitting Delays.—As discussed in chapter 4, several regulatory problems could delay deployment of a CAES plant. These plants employ a gas- or oil-fired combustion turbine. The operator of the plant must obtain an exemption from the Powerplant and Industrial Fuel Use Act of 1978. Other delays might result from environmental impacts; regulatory problems might arise regarding atmospheric emissions, well drilling and construction, water consumption and contamination, and cavern excavation. The relative inexperience of all concerned parties with CAES could further complicate the licensing and permitting process.

Batteries

Industry Description, History, and Outlook

Batteries first appeared in the 19th century and were quickly applied to railroads, telephones, and lights. Near the beginning of this century, the all-electric automobile appeared using batteries, but it was not until 50 years later that utilities used batteries to level loads in urban areas. For example, batteries were used in Chicago to compensate for the effects on the direct-current (DC) electric system of elevators and lights in large downtown buildings.[84] As the use of DC power systems declined in the 1930s, the use of batteries by utilities declined as well.[85]

Over the past dozen years, however, batteries for stationary applications have been the subject of renewed interest and development. Rapid technical progress has been made and batteries may eventually be used extensively in grid-connected applications to enhance peak load capacity.

At the forefront of battery development have been manufacturers in Western Europe, Japan, and the United States. Often closely affiliated with these R&D programs have been parallel efforts to develop batteries for mobile applications. Efforts directed towards stationary applications in the United States have been led by DOE, EPRI, and interested utilities, as well as by battery manufacturers themselves.

DOE and EPRI together have funded the construction and operation of the national Battery Energy Storage Test (BEST) Facility in New Jersey as a national center where prototype battery modules are tested and evaluated, along with other related equipment. The facility first began operating in 1982. By May 1985, both advanced lead-acid and zinc-chloride batteries had been tested in the facility. Sodium-sulfur (or beta) and zinc-bromide batteries are expected to be installed around 1989 or 1990.

The Japanese meanwhile have vigorously developed batteries under the auspices of MITI's Moonlight program since fiscal year 1980. The goal of the program is to demonstrate two 1 MWe, 8 MWh battery installations by 1990. As is the case in the United States, both utilities and their customers have been identified as prime markets.[86] Already the batteries are being used by utility customers in Japan; the Japanese National Railways, for example, has installed a Japanese-made lead-acid battery system.[87] Western European manufacturers are very active as well. Indeed, West Berlin became the location of the world's first large, modern, grid-connected battery installation. After operating a small prototype facility, the city's utility decided to build a 17 MWe, 14.4 MWh facility. Plant construction began in early 1985.[88]

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[83] Decision Focus Inc., *Compressed-Air Energy Storage: Commercialization Potential and EPRI Roles in the Commercialization Process* (Palo Alto, CA: Electric Power Research Institute, 1982), EPRI EM-2780.

[84] Jenny Hopkinson, "The New Batteries," *EPRI Journal*, vol. 6, No. 8, October 1981, pp. 6-13.

[85] Peter A. Lewis, *Elements of Load-Leveling Battery Design for System Planning*, paper presented at the International Symposium and Workshop on Dynamic Benefits of Energy Storage Plant Operation.

[86] Y. Ariga, et al., Central Research Institute of Electric Power Industry (Japan), "Optimum Capacities of Battery Energy Storage System for Utility Network and their Economics," *Advanced Energy Systems—Their Role in Our Future: Proceedings of the 19th Intersociety Energy Conversion Engineering Conference, Aug. 19-24, 1984* (San Francisco, CA: American Nuclear Society, 1984), paper 849050, pp. 1075-1080.

The battery technologies favored for widespread deployment in the 1990s are advanced lead-acid and zinc-chloride batteries. Both types of batteries have been successfully tested at the BEST Facility. The EPRI, vendors of both types of batteries, and others are laying the groundwork for the subsequent step for commercialization: multi-megawatt demonstration units within the next 5 years.

Early markets for the stationary batteries could reside with both utilities and nonutilities. Utilities can use batteries to level loads, shave peaks, regulate systems, or for spinning reserves. Nonutilities—commuter railways, for example—may use batteries to avoid the high cost of electricity during peak periods and to take advantage of lower prices during base periods. Recent analyses suggest that in some cases batteries could present very attractive investment opportunities.[89]

The strongest segment of the battery industry is concentrating on the lead-acid battery. About a half-dozen companies, primarily producers of automotive batteries, consider the large load-leveling batteries as a technology with considerable promise and have active R&D programs.[90]

Lead-acid batteries are strong contenders, in part because the precipitous drop in lead prices resulting from Government-mandated removal of lead from paint and gasoline has drastically reduced raw-material costs. In addition, the lead-acid battery industry is strong and well-established. However, while the industry is considered capable of financing the construction of a mass production facility, and though stationary markets have interested all the major battery manufacturers, to date they have been reluctant to make major investments. Apparently, they perceive the stationary market to be too unpredictable—particularly when compared to the automotive market. A major uncertainty lies with the effect changing gas and oil prices would have on the technological choices between batteries and conventional generating technologies in meeting the need for peaking capacity.[91]

Meanwhile, the development of the zinc-chloride battery has been shouldered mainly by one firm, Energy Development Associates (EDA).[92] The company has introduced a large, prototype commercial module, known as the "FLEXPOWER" commercial load-leveling battery. It is rated at 2 MWe, 8MWh. It plans to deploy the system in four stages, with the ultimate goal of commercially deploying the technology by the late 1980s or early 1990s.[93] Its design was "heavily influenced by the desire to meet both electric-utility and customer side-of-the-meter markets with similar hardware."[94] The demonstration phase for the system will include installation and operation of a system by an industrial customer.

Major Impediments to the Commercial Deployment of Batteries

The major impediments to the widespread commercial deployment of batteries in the 1990s are discussed below.

Technology Demonstration.—The successful testing of both lead-acid and zinc-chloride battery modules has provided encouraging evidence in favor of the batteries. Commercial-scale multi-megawatt installations are required, however, which will demonstrate the capabilities of the systems on a commercial scale, over extended periods, and under the variety of conditions expected of actual commercial plants. Until such demonstrations have taken place, extensive investment is unlikely.

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[87] Glenn Zorpette, "High-Tech Batteries for Power Utilities," *IEEE Spectrum*, vol. 21, No. 10, October 1984, pp. 40-47.

[88] Glenn Zorpette, "High-Tech Batteries for Power Utilities," op. cit., October 1984.

[89] Bechtel Group, Inc., *Updated Cost Estimate and Benefit Analysis of Customer-Owned Battery Energy Storage* (Palo Alto, CA: Electric Power Research Institute, January 1985), EPRI EM-3872.

[90] Arthur D. Little, *Commercialization Strategy for Lead-Acid Batteries in Utility Load Leveling Applications* (Cambridge, MA: Arthur D. Little, Inc., 1980), DOE/ET/26934-1.

[91] Ibid.

[92] A subsidiary of Gulf+Western Industries.

[93] B.D. Brummet, et al., *Zinc-Chloride Battery Systems for Electric-Utility Energy Storage*, paper presented at the 19th Intersociety Energy Conversion Engineering Conference, Aug. 19-24, 1984, San Francisco, CA.

[94] B.D. Brummet, et al., *Zinc-Chloride Battery Systems for Electric-Utility Energy Storage*, op. cit., 1984.

Equipment Cost and Performance.—Until demonstrations have been completed, and experience has accumulated, it will be difficult to precisely identify cost and performance impediments to commercial applications of batteries. A key variable affecting the future of lead-acid batteries will be the price of lead; low prices will be required to maintain acceptable costs.

For zinc-chloride batteries, the major variable probably will be the level of demand for the large stationary batteries. Low costs will depend on mass production; mass production in turn will require a sizable market. Vendors will be reluctant to invest in manufacturing capacity without strong indications that the market will absorb the quantities produced; yet the market is unlikely to develop until mass production drives prices down. This "chicken-or-the-egg" dilemma may be the least tractable of the impediments confronting developers of the zinc-chloride battery in the 1990s. This problem is considerably less serious with the lead-acid battery because many of the lead-acid battery's components can be produced with existing facilities dedicated to pre-existing markets. Lead-acid battery prices therefore are less sensitive to initial demand for the large stationary units.

Utility Rate Structures.—The price customers pay for the use of utility-generated electric power during peak periods may differ from the price paid during off-peak periods. A demand charge may be imposed based on a customer's peak demand (cost/kWe). Or, the energy charge (cost/kWh) may be higher during peak periods than during other times of the day. Hence, there is an incentive for the customer to shift consumption away from peak periods. One way of doing this is with batteries. With low demand and energy charges or no incentive pricing, however, a battery may not be justified. Or, even if the charges are high at present, the possibility that they may decrease (relative to off-peak rates) discourages customer investment in batteries. Current evidence indicates that both low charges and uncertainty over charges could be major impediments to customer investments in batteries.[95]

Licensing and Permitting.—Generally, the installation and operation of a battery unit will cause impacts far less serious than those associated with most competitors. In most cases, few regulatory delays are likely to result. But for zinc-chloride batteries, serious licensing and permitting delays might occur as a result of the possibility that large volumes of chlorine or bromine might be released accidentally from a proposed battery installation. Consideration of the possible problems is not likely to stop deployment in any particular instance. But difficulties, particularly with regulatory officials not well acquainted with the the technology or where the site is in a densely populated area, could arise and cause lengthy delays.

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[95] Bechtel Group, Inc., *Feasibility Assessment of Customer-Side-of-the-Meter Applications for Battery Energy Storage* (Palo Alto, CA: Electric Power Research Institute, 1982), EPRI EM-2769; and Electric Power Research Institute, *Utility Battery Operations and Applications* (Palo Alto, CA: Electric Power Research Institute, 1983), EPRI-2946-SR.

Chapter 10

Federal Policy Options

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Chapter 10

Federal Policy Options

OVERVIEW

Over the last several years, the need to diversify the electricity generation mix has become increasingly clear. Part of the strategy for meeting this policy objective has been sustained development of new electric generating technologies. With considerable uncertainty in load growth as well as other major policies affecting utility and nonutility decisions about new and existing power generating capacity, the attainment of a diverse generation mix has taken on added dimensions. Because of this uncertainty, it may be prudent to accelerate the availability of the technologies discussed in this study so that they could make a greater contribution in the 1990s than currently is expected.

Seeking diversity in electricity supply options is now not only being pursued to reduce dependence on oil but also in anticipation of the variety of future circumstances as discussed in the chapter 3, such as more stringent control of air pollution emissions or increased availability of natural gas. Developing technologies are of interest in the short term since they might contribute to ensuring a reliable and economic supply of electricity over the next two decades under a variety of these future circumstances. Many of these technologies also offer promise of fuel flexibility, increased efficiency, and other advantages. An increased contribution before the turn of the century, however, will require accelerated development of these new generating technologies, including progress in a number of critical areas. This is because *at the current rate of development* very few of the technologies considered in this assessment are likely to be deployed *extensively* in the 1990s.

Table 10-1.—Policy Goals and Options

Reduce capital cost, improve peformance, and resolve uncertainty:

1. Increase Federal support of technology demonstration
2. Shorten project lead times and direct R&D to near-term commercial potential
3. Increase assistance to vendors marketing developing technologies in foreign countries
4. Increase resource assessment efforts for renewable energy and CAES resources (wind, solar, geothermal, and CAES-geology)
5. Improve collection, distribution, and analysis of information

Encourage nonutility role in commercializing developing technologies:

1. Continue favorable tax policy
2. Improve nonutility access to transmission capacity
3. Develop clearly defined avoided energy cost calculations under PURPA
4. Standardize interconnection requirements

Encourage increased utility involvement in developing technologies:

1. Increase utility and public utility commission support of research, development, and demonstration activities
2. Strengthen provisions for utility subsidiaries involved in new technology development
3. Resolve siting and permitting questions for developing technologies
4. Other legislative initiatives: PIFUA, PURPA, and deregulation

Resolve concerns regarding impact of decentralized generating sources on power system operation:

1. Increase research on impacts at varying levels of penetration
2. Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

SOURCE: Office of Technology Assessment.

This chapter discusses a range of alternative policy initiatives that could accelerate the commercial deployment of developing generating and storage technologies in the 1990s. The goals and options are summarized in table 10-1. The first three:

A. Reduce capital cost, improve performance, and resolve uncertainty,
B. Encourage nonutility role in commercializing developing technologies, and
C. Encourage increased utility involvement in developing technologies,

are the primary goals; while the fourth:

D. Resolve concerns regarding the impact of decentralized generating sources (and load management) on power system operation,

is less critical although still important.

GOAL A: REDUCE CAPITAL COST, IMPROVE PERFORMANCE, AND RESOLVE UNCERTAINTY

As discussed in chapters 4 and 8, the current cost and performance characteristics (including uncertainty) of developing generating and storage technologies considered in this assessment generally do not yet compare favorably with either conventional generating options or other strategic options such as load management and life extension of existing powerplants. Of particular concern is the uncertainty in cost and performance anticipated in early commercial utility applications. Even in the case of load management, already being pursued aggressively by many utilities, widespread deployment of load management in the 1990s will depend on continued experimentation by utilities to resolve operational uncertainties; the refinement of load management equipment and techniques including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer acceptance.

The following are alternative policy options aimed at reducing cost, improving performance, and resolving uncertainty in both cost and performance.

Option A1: Increase Federal support of technology demonstration

A critical milestone in both utility and nonutility power producer acceptance of new technology is completion of a commercial demonstration program. There is considerable debate in the industry over what constitutes a demonstration program, but usually two basic categories are distinguished. One is a proof-of-concept phase which provides the basic operational data for commercial designs as well as test facilities designed to prove the viability of the technology under nonlaboratory conditions, and to reduce cost and performance uncertainties. The other involves multiple applications of a more or less mature technology designed to stimulate commercial adoption of the technology. In theory the distinction seems clear; in practice, it sometimes is not. Generally, though, activities in the first category are necessary for demonstrating technical feasibility, and activities in the second category are necessary for demonstrating commercial readiness and for accelerating acceptance by utilities or nonutility power producers.

The length of the appropriate demonstration period will vary considerably by technology. However, adequate demonstration periods (perhaps many years for larger scale technologies) are crucial to promoting investor confidence. Moreover, the nature of the demonstration program—i.e., who is participating, who is responsible for managing it, and the applicability of the program to a wide variety of utility circumstances—is crucial too, if utilities, in particular, are eventually to buy the technology.

Many utility decisionmakers argue that the perceived and real obstacles to adoption of developing generating technologies can be removed by "well-managed federally sponsored incentives and projects."[1] A key ingredient is the nature of the relationship between government and industry in such ventures. A cooperative research and development (R&D) partnership has proven to be a key ingredient in many successful demonstration programs. Demonstration programs should have the following characteristics:

- The private sector should have considerable influence in the selection of technologies for demonstration as well as principal responsibility for demonstration program design and management of the demonstration project itself.
- Private sector proprietary rights and ownership should be preserved, provided that such protection does not inhibit timely development of the technology.
- Cost sharing between government and industry has generally proved successful in ensuring both careful selection of the most

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[1] J. R. Straughn, Director of Research and Development, Southern California Edison Co., testimony before the House Committee on Science and Technology, Subcommittee on Energy Development and Applications, June 13, 1984.

competitive projects and timely completion of the projects.

- Federal Government commitments to a demonstration program should be stable and predictable—i e., once made, such commitments should be honored for a sufficient period in order to convince developers that government is a "reliable partner."
- First-of-a-kind, full-scale demonstration facilities should include support by all partners involved in the demonstration program for not only plant engineering and construction but also for extended plant operations.[2]

Smaller modular plant designs, where possible, are very attractive for demonstration projects since they normally require a smaller capital commitment than large central station designs. In addition, successful demonstration projects have included active participation from a wide range of private sector interests such as architect-engineering firms, equipment manufacturers, as well as the utilities themselves when appropriate.

Option A2: Shorten project lead-times and direct R&D to near-term commercial potential

Virtually all of the technologies considered in this assessment offer the potential of sizable deployment in electric power generation applications beyond the turn of the century. *At the current rate of development*, however, few of these technologies are likely to be extensively put in place in the 1990s. Under conditions of accelerated load growth in the 1990s, an increase in or a refocusing of current Federal research, development, and demonstration (RD&D) activities could accelerate the deployment of early commercial units for most of the technologies considered in this assessment. This includes attention not only to the technologies themselves, but also to manufacturing techniques and equipment necessary to produce the technologies.

While the technologies considered here encompass a wide range of sizes, scales, and levels of technological maturity, for purposes of discussing appropriate policy actions, it is convenient to divide them into two basic groups:

- The first consists of technologies envisioned primarily for direct electric utility applications, including integrated gasification/combined-cycle (IGCC) plants, large (>100 MW) atmospheric fluidized-bed combustors (AFBC), large (>100 MW) compressed air energy storage (CAES) facilities, large (>50 MW) geothermal plants, utility-owned fuel cell powerplants, and solar thermal central receivers.
- The second group consists of technologies suitable either for utility or nonutility applications, including fuel cells and small (<100 MW) AFBCs in nonutility cogeneration applications, small (<100 MW) CAES, wind turbines, small (<50 MW) geothermal plants, batteries, and other solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

A characteristic of the first group of technologies is the likelihood of long preconstruction and contruction lead-times—up to 10 years. Although these technologies have the potential for much shorter lead-times—5 to 6 years—problems associated with any new, complex technology may require construction of a number of plants before that potential is met. If the longer lead-times are needed, deployment in the 1990s will be limited because of short time remaining to develop the technologies to a level acceptable to a broad array of utilities.

The technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. For increased contribution in the 1990s, however, most of these technologies will require stepped up development to reduce cost and resolve cost and performance uncertainties that concern utility decisionmakers and nonutility investors.

It is important to note that this division between these two groups of technologies is not rigid. Some technologies the first group could also benefit from accelerated R&D and some in the second group could benefit from policies aimed at shortening lead-times. This overlap should be considered in applying policy actions to either group.

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[2] Adapted from D. Spencer, Electric Power Research Institute, "Remarks on the Importance of a Federal Government Role in Supporting Demonstration Scale Facilities for Fossil and Renewable Energy Technologies," testimony presented to the House Committee on Science and Technology, Subcommittee on Energy Development and Applications, June 7, 1984.

Generally, though, the steps necessary to accelerate contribution to electricity supply vary according to the technology. With the first group of technologies, it is necessary, first, to resolve cost and performance uncertainties within the next 5 to 6 years; and second, to take steps to achieve the short lead-time potential for early commercial units. Uncertainties in cost and performance stem largely from the lack of sufficient commercial operating experience to satisfy nonutility investors and utility decisionmakers. Utility decisionmakers, in particular, in the wake of their experience with nuclear power, are now particularly wary of new technology, especially large-scale technology, and they impose rigorous performance tests on technology investment alternatives. This conservatism confers added importance to advanced commercial demonstration projects, as mentioned earlier in option A1.

On the other hand, no significant acceleration of existing RD&D schedules for the *basic* designs of the IGCC, large AFBC, and utility-scale geothermal plants is likely to be required for these technologies to be ready for the 1990s. Their transition from demonstration to early commercial units, however, will have to be accelerated if the technologies are to be used in serving demand growth in the 1990s if it occurs. Variations in basic designs or more advanced designs, however, will require additional R&D.

Lead-times being experienced by early commercial projects in both groups of technologies have been longer than anticipated, partially due to the time required for regulatory review. As regulatory agencies become more familiar with the technologies, and their environmental benefits become clearer, the review process should become smoother and more predictable, although this is by no means guaranteed as evidenced by the history of other generating technologies. If there is accelerated demand growth, however, it may be necessary to take those actions to ensure lead-times consistent with those possible for these technologies. Such actions include working closely with regulators, and careful management of construction and early operation. By emphasizing smaller unit size—200 to 300 MW—these actions would be made easier. The success of the Cool Water project shows that such actions are possible and effective.

For the technologies in the second group, where cost and performance are of particular concern, one approach to accelerating development would be to increase or concentrate Federal R&D efforts on those technologies. This could be particularly effective for photovoltaics, solar thermal parabolic dishes, and advanced small geothermal designs.

Option A3: Increase assistance to vendors marketing developing technologies in foreign countries

The new generating technologies that appear to show the most promise for substantial deployment in the 1990s are those that currently serve or have the opportunity to serve markets other than the domestic utility grid. Such markets are especially important as long as demand growth for new electric generating capacity is low and while cost and performance of these technologies are uncertain in grid-connected applications. For some of these technologies these markets are foreign. Efforts on the part of the U.S. Government to assist in establishing access to markets for new generating technology equipment in foreign countries could be very important to the near-term viability of some of these technologies. Such efforts might include support for formation of renewable export trading companies, loan guarantees, information dissemination, and help with joint venture and licensing applications in foreign countries.

The pressures of competition from foreign vendors, many of which are heavily supported by their governments, as well as the current lack of U.S. demand for some of these new technologies in grid-connected power generation applications raises the concern over the continued commitment of U.S. firms to developing these technologies. This concern is heightened by pending changes in favorable tax treatment for renewable energy sources. For some domestic firms who are working on technologies such as wind, solar thermal electric, and photovoltaics (at least those focusing on concentrator technologies), the survival of some domestic firms may be at stake. They may not be able to or willing to compete in world markets over the next decade. However, they may need those markets until their technologies can compete in the U.S. grid-connected power generation market.

Option A4: Increase resource assessment efforts for renewable energy resources

In those regions where renewable energy sources show promise for commercial application, a well-defined resource is essential for assessing the economics of proposed wind, geothermal, and solar power generating projects and for CAES projects. For example, there can be a several hundred percent difference in the energy generated by the same wind machines using different distributions of the same annual mean wind speed; an untested site may require up to 3 years of data to confirm the extent and nature of the wind resource at that site.

Reliable resource data lessens the uncertainty in energy production and hence the risk of insufficient project revenues. Some industry observers[3] feel that, at least in the case of wind, "knowledge of the wind resource—its location and intensity—is the cornerstone to the development of wind energy."[4] Lack of a detailed resource base is also an important factor in geothermal development and, to a lesser extent, in solar thermal electric and photovoltaic development.

Option A5: Improve collection, distribution, and analysis of information

A serious disadvantage facing all the developing technologies is the lack of adequate information on the technologies and their markets among those whose decisions are important to their commercial deployment—investors, regulators, the general public and others.[5]

Nonutility market information, in particular, is generally not available because these markets are not yet well developed.[6] The lack of information increases the general level of uncertainty and risk, and favors conventional technologies and markets about which more is known.

Programs designed to deliver accurate and useful information in a timely manner to the relevant individuals and groups would be helpful in accelerating deployment of the technologies. Also, efforts to increase the capability to use the information properly could be effective. Such efforts might include the training of individuals, the development of appropriate analytical methods, and acquainting people with the technology through demonstration projects.[7]

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[3] *Final Report of the Wind Energy Task Force*, unpublished report, Oregon Alternate Energy Development Commission, June 1980.

[4] S. Sadler, et al., *Windy Land Owners' Guide* (Salem, OR: Oregon Department of Energy, 1984).

[5] This is a common impediment encountered by developing technologies during the commercial transition. See Arthur D. Little, Inc., *Barriers to Innovation in Industry: Opportunities for Public Policy Changes* (Washington, DC: Arthur D. Little, Inc., 1973).

[6] The inadequacy of information on nonutility markets was pointed out in: "FERC Wants Cogeneration Tally; Results May Question Central Plant Need," *Electric Utility Week*, Mar. 18, 1985, p. 3. The article raises the possibility that the failure to adequately consider nonutility power producers may severely distort analyses such as those performed by the Department of Energy. The Energy Information Administration, for example, in its *Annual Energy Outlook-1984*, does not include any nonutility capacity in its calculations of plant construction through the year 1995.

[7] For an informative discussion of the importance to public utility commissions of the collection, distribution, and analysis of information, see: S. Wiel, Commissioner, Public Service Commission of Nevada, Statement before the Subcommittee on Energy Development and Applications, Committee on Science and Technology, House of Representatives, U.S. Congress, Mar. 5, 1985.

GOAL B: ENCOURAGE NONUTILITY ROLE IN COMMERCIALIZING DEVELOPING TECHNOLOGIES

Option B1: Continue favorable tax policy

The Renewable Energy Tax Credits (RTCs) have been an important contributor to the Federal policy of supporting the infant renewable energy industry.[8] While the RTCs have been in effect since 1978, they have only been utilized to a significant degree since 1981 for electric power projects and are only applicable to nonutility facilities. For wind projects, in particular, the credits seemed to have spurred development significantly for two reasons:

1. With the tax credits, projects with design specifications using current cost and performance technology present competitive rates of return for prospective investors, particularly in California where State tax credits and high PURPA avoided cost rates are additional incentives. Even if the design specifications for a prospective project are not realized, as has been the case for a large number of first generation wind projects, the tax benefits alone associated with these projects, many of which were initiated to test innovative designs, have been sufficient to attract considerable investment interest. This has been particularly true for investors with income from other investments.

   For example, using OTA's cost and performance estimates (appendix A), the cumulative tax benefits—including accelerated depreciation allowances (ACRS), Investment Tax Credits (ITCs), and RTCs—shows that wind turbines as well as geothermal projects are attractive investment opportunities under all reasonable cost and performance scenarios. PVs become competitive under the "best case" scenario. Some of the details of this analysis are illustrated in figure 10-1.[9]
2. While the first generation wind projects in California generally did not perform well, they served as the "test bed" for small wind machines (less than 200 kW) that have not been the focus of the Federal R&D program. Indeed, the wind industry is currently moving from these first generation small machines to medium-sized machines (200 to 1,000 kW) as the technology matures.

The effect of the RTCs on internal rates of return for solar, geothermal, and wind projects is shown in figure 10-1, including the "worst case," "most likely," and "best case" cost and performance scenarios defined in chapter 4 and appendix A. It should be noted that special investment structures such as safe harbor leases or other tax leveraged vehicles can improve the attractiveness of the investment considerably by limiting risk and/or offering substantial tax benefits (as discussed in chapter 8). Such mechanisms have become more the rule than the exception in the industry in the last several years. As renewable technology matures, the quality of investments will improve regardless of the tax implications, if avoided cost rates remain sufficient as shown in the figure. Figure 10-2 shows the breakeven avoided cost (buy-back) rates necessary to yield a 15 percent real internal rate of return.

The role of the RTC in accelerating commercial development seems to have changed from its original design, at least for the technologies considered in this assessment. The original Federal policy was to provide direct research support to develop the technology and the RTC to accelerate commercial deployment. With decreased Federal R&D support, the RTC appears

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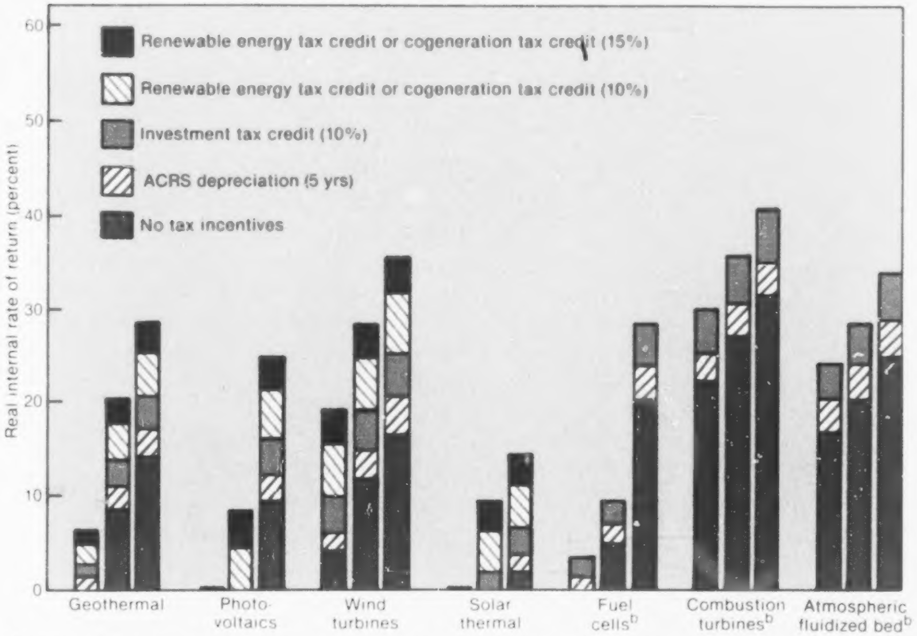
[8] The Energy Tax Act of 1978, the long-term "support of an infant industry" motivation for the renewable energy credit was quite different from the sister tax credit for conservation which was motivated by the short-term objective for encouraging energy conservation.

[9] Also see P. Blair, testimony presented in hearings held by Subcommittee on Energy and Agricultural Taxation, Committee on Finance, U.S. Senate, June 21, 1985.

Figure 10-1.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return[a]



[a] Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.
[b] In cogeneration applications.

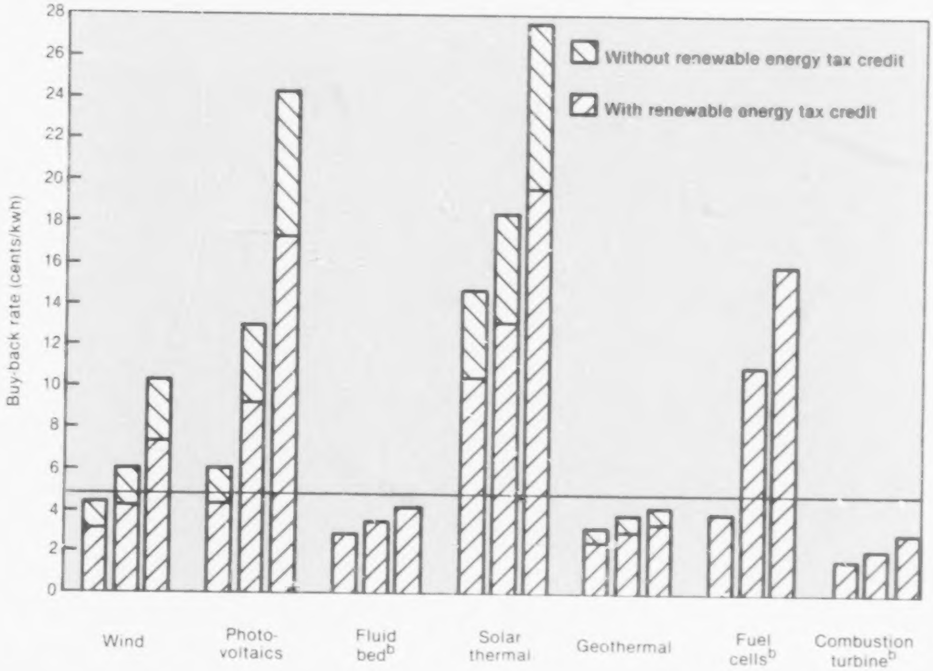
SOURCE: Office of Technology Assessment, U.S. Congress.

to be supporting research and development in the field as well as commercial development. At the same time, there are instances where the RTC has prompted installation of inferior technology that has little possibility of commercial success.

These instances have brought about criticism of the RTCs, particularly for wind, that has resulted in proposals for an alternative PTC that would award the credit based on energy generated rather than the initial investment. These critics have argued that support of innovative designs is not the intent of the credits. Indeed, a PTC would discourage investment primarily oriented toward exploiting tax benefits. Moreover, it would ensure that whatever investments are made would be done so for energy production purposes. A PTC, however, may be difficult to monitor, particularly in non-grid-connected applications. In addition, while PTCs may ensure better performance, it may slow technology development and commercialization since investors would be less likely to test innovative designs. Another implication of the PTC, compared with the RTC, is that it favors technologies in base load cycle applications (with higher capacity factors) such as geothermal and penalizes those in intermediate and peaking applications such as wind or solar. The trade-offs between PTCs and RTCs are illustrated in table 10-2.

The evidence supporting the relative effectiveness of tax incentives for stimulating investment in the electric utility industry itself is not as compelling as the nonutility case. For example, the decrease in the levelized per kilowatt-hour busbar cost for the renewable technologies considered in OTA's assessment, with a 15 percent tax credit over and above the existing tax benefits currently afforded to utilities, is less than 10 percent for all cases. The relative lower effectiveness is mostly explained by utility accounting practices

Figure 10-2.—Breakeven Utility Buy-Back Rates[a]



[a] Reported for each technology with "best case," "most likely," and "worst case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8, chart shows buy-back rates necessary to generate a 15% real rate of return on investment.
[b] In cogeneration applications.

which spread the benefits of the tax credit over the life of the facility rather than offering a substantial front-end incentive. For electric utilities, other actions than tax preferences (discussed later) may be more effective in stimulating development of new technology.

Since the early 1970s, the Federal policy for encouraging the development of a renewable energy industry centered on an active R&D program to develop the technology (particularly active during the decade of the 1970s) coupled with the tax credits (since the early 1980s) to spur commercial applications. This analysis shows that with declining direct support from Federal RD&D programs, the pace of renewable technology development would slow considerably without the RTC. Indeed, without the credits, only the most mature renewable technologies at the best resource locations would likely be deployed through the 1990s. Even with the tax credits, the application of the renewable technologies considered here will be highly regionally dependent in the 1990s (see chapter 7). In regions where the wind, solar, and geothermal resources are of high quality, though, the renewables could be important contributors to both new and replacement generating capacity.

Many industry observers argue that a gradual phasing out of the RTC rather than their currently scheduled termination at the end of 1985 would give the renewable power industry a better chance to develop technology to the point where it might compete effectively in the 1990s. In particular, a 3-year phase-out of the credit for wind and geothermal could benefit those technologies considerably and increase deployment in the

Table 10-2.—Alternative Tax Incentives: Cumulative Effect on Real Internal Rate of Return

	Real internal rate of return (percent)						
Tax incentive	Geothermal	Photo-voltaics	Wind turbines	Solar thermal	Fuel cells	Combustion turbine	Atmospheric fluidized-bed
"Worst case" cost and performance:							
No tax incentives[a]	0.1%	0.0%	4.1%	0.0%	0.0%	22.3%	16.9%
Current tax incentives[b]	4.9	0.0	19.1	0.0	3.4	30.0	24.3
Investment Tax Credit (10%)[c]	2.7	0.0	9.9	0.0	3.4	30.0	24.3
Production Tax Credit: [d]							
$0.01/kWh	6.3	0.0	14.9	0.0	7.7	39.1	29.8
$0.02/kWh	6.7	0.0	16.8	0.1	8.6	40.5	31.7
$0.03/kWh	6.8	0.0	17.9	0.1	9.1	40.5	32.0
$0.05/kWh	7.0	0.0	19.0	0.2	9.5	40.5	33.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	2.8	0.0	11.6	0.0	3.6	32.0	24.6
10% with 5 year ACRS	4.9	0.0	15.5	0.0	6.6	36.1	29.6
15% without 5 year ACRS	3.8	0.0	14.5	0.0	5.1	35.3	27.3
15% with 5 year ACRS	6.3	0.0	19.1	0.0	8.9	39.7	32.9
ACRS depreciation:[f]							
5 years	1.2	0.0	5.9	0.0	1.3	25.2	20.2
10 years	1.1	0.0	5.1	0.0	1.2	23.2	18.6
"Most likely" cost and performance:							
No tax incentives[a]	8.9%	0.0%	11.7%	0.0%	5.0%	27.2%	20.4%
Current tax incentives[b]	17.8	8.4	28.4	9.5	9.5	35.8	28.6
Investment Tax Credit (10%)[c]	13.9	0.0	18.9	1.8	9.5	35.8	28.6
Production Tax Credit: [d]							
$0.01/kWh	19.2	5.2	24.6	6.1	14.1	46.2	34.9
$0.02/kWh	20.4	6.7	26.6	7.5	15.3	47.0	37.0
$0.03/kWh	20.8	7.5	27.8	8.2	15.9	47.0	37.9
$0.05/kWh	21.2	8.4	28.8	9.1	16.3	47.0	38.8
Renewable Tax Credit:[e]							
10% without 5 year ACRS	13.9	1.5	19.7	2.1	9.5	38.1	29.1
10% with 5 year ACRS	17.8	4.3	24.7	6.2	13.3	42.3	34.4
15% without 5 year ACRS	15.8	4.3	22.7	4.0	11.3	41.7	32.2
15% with 5 year ACRS	20.4	8.4	28.4	9.5	15.8	46.2	37.9
ACRS depreciation:[f]							
5 years	11.2	0.0	14.7	0.0	7.0	30.5	24.1
10 years	10.3	0.0	13.2	0.0	6.4	28.2	22.3
"Best case" cost and performance:							
No tax incentives[a]	14.2%	9.4%	16.6%	1.7%	20.3%	31.5%	24.8
Current tax incentives[b]	25.5	24.8	35.5	14.4	28.4	40.7	33.9
Investment Tax Credit (10%)[c]	20.7	16.0	25.2	6.6	28.4	40.7	33.9
Production Tax Credit: [d]							
$0.01/kWh	27.0	20.6	31.9	10.2	36.4	52.5	41.0
$0.02/kWh	28.4	22.6	34.2	11.8	38.1	52.5	43.2
$0.03/kWh	29.1	23.7	35.2	12.7	38.6	52.5	44.3
$0.05/kWh	29.4	24.7	36.4	13.8	38.6	52.5	44.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	20.8	16.0	25.6	6.7	28.9	43.3	34.7
10% with 5 year ACRS	25.5	21.3	31.6	11.2	34.2	47.6	40.2
15% without 5 year ACRS	23.3	18.7	28.9	8.7	32.0	47.1	38.1
15% with 5 year ACRS	28.6	24.8	35.5	14.4	37.7	51.6	43.9
ACRS depreciation:[f]							
5 years	17.1	12.3	20.5	3.7	24.0	35.0	28.9
10 years	15.8	11.1	18.6	3.3	22.1	32.4	26.7

[a] Includes Sum of Years Digits depreciation, no Investment Tax Credit (ITC), and no Renewable Tax Credit (RTC).

[b] Includes 5 year ACRS depreciation, 10% ITC, and RTC where applicable.

[c] Includes 5 year ACRS and 10% ITC.

[d] The Production Tax Credit (PTC) is calculated by applying the cents/kWh credit amount to expected yearly electricity production. The credit is applied annually until the cumulative tax credit equals the 15% RTC. The 10% ITC and the 5 year ACRS schedule are also used in computing the PTC.

[e] Includes 10% ITC.

[f] Does not include 10% ITC.

SOURCE: Office of Technology Assessment.

1990s. For solar thermal and photovoltaics, however, a 5-year or more extension or gradual phase-out would more likely be required.

Option B2: Improve nonutility access to transmission capacity

Some nonutility power producers argue that if proposed nonutility generating projects were included more explicitly in utility resource planning considerations, such projects might be better aligned with proposed transmission expansion and reconfiguration plans. Coordination of nonutility generation with utility-owned generation must be balanced against utility concerns about control of generating sources for dispatching and maintenance of system reliability.

Nonutility generating sources might also be more prevalent if power from projects located in one utility service territory could be sent to another utility service territory where, for example, avoided cost payments were higher. Such "wheeling" of power, however, requires transmission capacity to be committed to the project in the former service territory. At low penetration levels of nonutility generating sources wheeling is not likely to be a serious problem. Some State utility commissions have already made wheeling mandatory. At higher levels of penetration, however, utilities might be forced to reconfigure or upgrade existing transmission capabilities to accommodate wheeling and the question of allocation of costs for upgrades becomes an issue.

If the objective is to increase nonutility power projects employing new electric generating technologies, revisions to PURPA to modify the wheeling provisions originally enacted might be an effective way to encourage development of such projects. Such modifications could give these producers access to utility markets beyond the service territory in which the project is sited without negotiating complicated individualized wheeling agreements with the local utility. Such modifications might also extend to obligations on the part of the utility in which a project is sited to negotiate with prospective nonutility producers on the issue of transmission access.

Modifications to PURPA to broaden the wheeling provisions, however, would have to be carefully constructed since the implications of such modifications vary greatly from region to region as well as from utility to utility within regions. Utility concerns about efficiency and control over the transmission and distribution system must be carefully addressed in any proposed modifications.

Finally, streamlining of Federal licensing and permitting procedures where such procedures apply to transmission projects—i.e., on Federal lands—could reduce the time it takes for PURPA-qualifying facilities to gain access to transmission capacity.

Option B3: Develop clearly defined and/or preferential avoided energy cost calculations under PURPA

In chapter 8 the avoided energy (and capacity) cost that utilities pay to nonutility producers for generated power was identified as one of the key factors affecting the profitability of nonutility power projects. Investors in nonutility power projects seek secure, long-term energy credit and capacity payment agreements with utilities to ensure a stable revenue stream for the project. In States encouraging nonutility projects, e.g., California, standard agreements have evolved that are levelized pricing contracts or fixed price schedules negotiated for the duration of the proposed projects. Such standard contracts have greatly increased nonutility generating activity in these States and could provide a model for other States.

In other States, public utility commissions have mandated minimum avoided cost rates—e.g., New York and Iowa have minimum rate of 6 and 6.5 cents/kWh, respectively, for small power producers which are generally above the prevailing avoided cost of the utilities. Attempts to remove such rates through the courts have to date been unsuccessful, although some appeals are still pending. If the courts interpret the primary purpose of PURPA's avoided cost provisions as encouraging small power production, then adoption of such mandatory rates could serve to accelerate small power production substantially in States where these rates exist. If, on the other hand, the courts rule that implementation of PURPA's avoided cost provisions' must consider immediate rate savings for a utility's customers, the future of such rates is less clear since public utility commissions will be obligated to strike a balance between customer savings and incentives for small power producers. The outcome is of considerable importance to the rate of commercial deployment of new generating technologies. Legislative action to co-opt the courts' decisions in this area could serve to reduce uncertainty, and in the process, accelerate deployment of new generating technologies that would qualify for mandatory rates where they exist.

Option B4: Standardize interconnection requirements

As the penetration of nonutility owned and operated dispersed generating sources (DSGs) increases in U.S. electric power systems, the implications for system operation, performance, and reliability are receiving increased attention by the industry. For the most part, however, the technical aspects of interconnection and integration with the grid are fairly well understood and most utilities feel that the technical problems can be resolved with little difficulty. State-of-the-art power conditioners are expected to alleviate utility concerns about the quality of interconnection subsystems.

Prior to 1983, most interconnection configurations were custom-fitted and no standardized guidelines existed. Since 1983, however, the number of applications from DSGs has increased and, as a result, more utilities are developing such guidelines. These individual utility guidelines vary widely, but a number of national "model" guidelines are being developed by standard-setting committees (discussed in chapter 6), although none has yet released final versions. Indeed, these groups are expected to continue to revise draft standards. Even if a consensus standard does emerge, however, widespread utility endorsement is still uncertain. As a result, DSG customers are likely to face different and sometimes conflicting interconnection equipment standards well into the 1990s. This lack of standardization may hamper both the use of DSGs as well as the manufacture of standardized interconnection equipment. Development of a set of national standards for interconnection that could be flexibly interpreted for individual utility circumstances could accelerate deployment of nonutility power projects in many regions.

GOAL C: ENCOURAGE INCREASED UTILITY INVOLVEMENT IN DEVELOPING TECHNOLOGIES

Electric utilities on average currently spend less than 1 percent of gross revenues on R&D, considerably less than most other capital-intensive industries. Traditionally, the response to this concern is that equipment manufacturers and vendors are carrying the principal burden of R&D for the power industry. But, with the decline in new equipment orders in recent years, manufacturers are less likely to commit R&D to new products for which strong markets are not assured. As a result, if R&D activity in new generating technologies is to continue, at least a portion of the burden may fall on the utilities themselves. With environmental and other pressures on utilities to consider new technologies, how public utility commissions treat cost of RD&D and of early commercial applications is a pivotal issue. The following are alternative strategies aimed at improving this regulatory environment.

Option C1: Increase utility and public utility commission support of RD&D activities

Increased RD&D activity in new generating technologies will require utilities and utility commissions to agree on appropriate mechanisms for supporting such activities. Direct support from the rate base for research activities, such as the allowance for contributions to the Electric Power Research Institute while desirable and important, is not now at a level that would cause significant deployment of these technologies by the 1990s. Allowance of or even encouragement of a higher percentage of annual revenues to support RD&D activities could be an important step in accelerating commercial applications of new technologies.

Even larger RD&D commitments, however, that involve large capital investments for major demonstration facilities may only be justified by a sharing of the risk between ratepayers, stockholders and, if other utilities would benefit substantially, taxpayers. One mechanism for supporting such projects is to finance a portion of proposed project with an equity contribution from the utility and the rest through a "ratepayer loan" granted by the public utility commission. The public utility commission might argue that a candidate demonstration project is too risky for the ratepayer to be subsidizing, particularly if other utilities could benefit substantially from the outcome, but are not contributing to the demonstration, i.e., sharing in the risk. In such cases, there could be a Federal role. For example, the ratepayer contribution to the demonstration could be underwritten by a Federal loan guarantee, thus transferring at least a portion of the investment risk from the ratepayer to the taxpayer.

Finally, since high interest rates and high capital costs have discouraged utilities from making investments in new generating capacity, a wide variety of regulatory changes have been suggested that would make it easier to resume construction programs. These include:

1. rate base treatment of utility assets that take inflation into account—sometimes called "trending" the rate base;[10]
2. allowance of some or all construction work in progress (CWIP) to be included in the rate base; and
3. adoption of real rates of return on equity commensurate with the actual investment risk.

These options are all aimed at evening out rate increases (prevention of so called "rate shock") and providing more financial stability for utilities. They would, however, reduce the attractiveness of smaller, modular generating technologies relative to larger units since the options transfer some of the investment risk from the stockholder to the ratepayer. While all capital projects—large or small—would benefit by this risk transfer in terms of lower capital costs, the larger the project the greater the net savings to the utility. Whether this is sufficient to outweigh the benefits of smaller units in a period of uncertain demand growth would depend on the particular utility and its longer term outlook.

Option C2: Promote involvement of utility subsidiaries in new technology development

Some electric utilities are using (and many are considering) the use of regulated or unregulated affiliated interests (corporate subsidiaries or other holding company structures) to initiate new technology projects where they have identified a project as an attractive investment opportunity but riskier than more traditional utility investments, i.e., the utility's allowed rate of return is not commensurate with the project's perceived financial risk. In practice, this usually amounts to a situation where the public utility commission agrees to permit a project to proceed but does not give assurances that the entire final project cost will be permitted to enter the rate base.

Using an unregulated affiliated interest to carry out new technology projects allows utilities to finance such projects with sources from the capital markets since higher rates of return can be offered to attract capital. It is also one example of how utilities are diversifying into other lines of business. As discussed in chapter 3, electric utility diversification activities are already widespread and growing. Most of these activities (74 percent according to a recent Edison Electric Institute survey) involve fuel exploration and development, real estate, energy conservation services, fuel transportation, district heating and cogeneration, and appliance sales. A small percentage (6 percent) do, however, involve alternative technology projects. Generally diversification has led to:

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[10] Trended rate base proposals are discussed in U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216.

1. A higher return for investors, increase in price-earnings ratio and, as a result, an improved standing in the financial community and a lowering in the cost of capital. Diversified utilities have consistently outperformed nondiversified utilities in the stock market.
2. More efficient use of company assets including labor, customer base, computational facilities, and services.
3. Diversification, protection, and stable pricing of fuel supplies through diversification into fuel acquisition activities and alternative technology projects.
4. An ability to take advantage of favorable tax benefits not afforded to regulated public utilities.

The problems of potential cross-subsidization of unregulated projects from regulated interests has to be monitored closely by public utility commissions as they allow utilities to become involved in diversification activities.

Option C3: Resolve siting and permitting questions for developing technologies

To date, the rate of deployment of some new generating technologies in both utility and nonutility applications is being lowered because lead-times being experienced by early commercial projects have been longer than anticipated, partially due to the time required for regulatory review. As regulatory agencies become more familiar with the technologies and their environmental impacts become clearer, the time to complete such reviews could decrease, although as noted earlier this is by no means guaranteed. Action to educate regulators and all others who would ultimately be affected by eventual deployment of the technology in the course of demonstrations might reduce the lead-times of early commercial units. For example, close coordination with State and Federal regulatory agencies as well as public utility commissions during demonstration projects should be a major feature of these projects. Finally, as noted for nonutility projects discussed earlier, streamlining of Federal licensing and permitting procedures where such procedures apply to transmission projects could reduce lead-times considerably.

Option C4: Other legislative initiatives: PIFUA, PURPA, and deregulation

In addition to maintaining a continued presence in research, development, and demonstration as well as implementing environmental policy affecting power generation, e.g., administration of the Clean Air Act, several possible Federal policy decisions affecting electric utilities could influence the rate of commercial development of new generating technologies over the next 10 to 15 years. These include removal of the Powerplant and Industrial Fuel Use Act (PIFUA) restrictions on the use of natural gas, extension of complete PURPA Section 210 benefits to electric utilities, and increased steps toward deregulation of power generation and bulk power transfers. All of these actions could increase the rate of deployment of developing generating technologies, but their other effects have to be carefully reviewed before and during implementation.

If increased availability of natural gas should occur, a repeal of PIFUA or, at a minimum, a more liberal policy on granting exemptions in power generation applications could, in addition to providing more short-term fuel flexibility for many utilities, be a step toward accelerated deployment of "clean coal" technologies such as the IGCC since they can use natural gas as an interim fuel. In addition, some technologies such as CAES and some solar thermal electric units use natural gas as a supplementary fuel and may or may not fall within the applicable size limits established by PIFUA automatically exempting such installations from the Act.[11] Where exemptions are required, their acquisition introduces delays or even the possibility that approval might be denied.

Permitting utilities to participate more fully in the PURPA Section 210 benefits of receiving avoided cost in small power production would most likely result in increased deployment of small modular power generating technologies, particularly cogeneration.[12] For example, utilities are currently limited to less than 50 percent participation in PURPA qualifying cogeneration facilities. In addition, ratepayers would likely see more of the cost savings resulting from cogeneration if utilities were allowed full PURPA benefits. Currently, ratepayers see only the difference, if any, between the avoided cost and the rate negotiated between the cogenerator and the utility. The owner of the qualifying facility retains the rest of the excess over the cost of generating the power. Similar benefits would accrue to the ratepayer by utility participation in PURPA for other types of generating technologies to the extent that costs of power production fall below avoided costs.

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[11] Changes in PIFUA would also affect nonutility producers, as discussed in ch. 9.

In relaxing this limitation, potential problems requiring attention include ensuring that utilities do not show undue preference for utility-initiated projects in such areas as access to transmission or capacity payments. Moreover, project accounting would probably need to be more segregated from utility operations than non-PURPA qualifying projects in order to ensure that cross-subsidization does not occur that would make utility-initiated projects appear more profitable at the expense of the ratepayer. These concerns can be allayed through carefully drafted legislation or regulations, or through careful State review of utility ownership schemes.

It should be noted, though, that granting of full PURPA benefits to utilities would be viewed with disfavor by most nonutility owners. In particular, allowance of such benefits likely would cause avoided costs to be determined by the cogeneration unit or alternative generation technology itself rather than the fuel and/or capital costs of a conventional plant that would be avoided by a utility as is currently the case. Unless prospective nonutility owners could produce power still cheaper than these newly defined avoided costs, they obviously would not enter into any projects. This would clearly reduce the number of cogeneration and alternative technology power projects started by nonutility investors. This drop-off, however, might be more than compensated by expanded utility involvement. It is also possible that potential cogeneration and alternative technology sites may go unfulfilled if utilities were allowed full PURPA benefits, since many of these site owners—industrial firms and large buildings—may not want utility control over facilities on their site. Here, too, careful establishment of regulations or contracts could protect all parties of interest.

Finally, as perhaps a logical next step to PURPA, a number of proposals for deregulation of the electric power business have been proposed in recent years, ranging from deregulation of bulk power transfers among utilities, to deregulation of generation, to complete deregulation of the industry. While OTA has not examined the implications of alternative deregulation proposals on the rate of commercial development of new generating technologies, such proposals would almost certainly have an impact. The experiences of PURPA and the FERC Bulk Power Market Experiment[13] will be important barometers for assessing the future prospects and desirability of deregulating U.S. electric power generation. It is important to note that allowance of full PURPA benefits for utilities would be a significant step toward deregulation of electric power generation, at least for smaller generation units.

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[12] For a more complete discussion, see U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-192, pp. 20ff.

[13] This experiment deregulates wholesale bulk power transactions among four utilities in the Southwest; see "Opinion and Order Finding Experimental Rate To Be Just and Reasonable and Accepting Rate for Filing," Federal Energy Regulatory Commission, Opinion No. 203, December 1983.

GOAL D: RESOLVE CONCERNS REGARDING IMPACT OF DECENTRALIZED GENERATING SOURCES ON POWER SYSTEM OPERATION

In recent years, utilities that interconnect with nonutility power producers operating DSGs are concerned about the potential impact of increased penetration of DSGs on overall power quality available in the utility grid as well as proper metering, effect on system dispatching and control, short-term transmission and distribution operations, and long-term capacity planning.

As utilities gain experience with DSGs on their own systems, these concerns are being resolved. However, many utilities are only beginning to gain this experience; the following options are aimed at addressing such concerns.

Option D1: Increase research on impacts at varying levels of penetration

While most of the problems associated with incorporating DSGs into the utility grid appear to have technical solutions, the cost and complexity of these solutions may vary considerably across utility systems. In particular, one concern is the potential impact on power quality of high levels of penetration of DSGs on individual distribution feeders. Other issues include protective equipment performance, appropriate safety procedures, system control at the distribution level, and impact on system generation dispatching procedures. Most research to date indicates that at low levels of DSG penetration—up to 5 percent of total installed capacity—there are no ill effects on system operations as measured by indicators such as the area control error (see chapter 6). Beyond a 5 percent penetration, however, there is less agreement among researchers. Research on the conditions under which DSGs would significantly affect system operation over a wide range of utility circumstances would improve utility engineers' ability to assemble appropriate and cost-effective interconnection configurations and control procedures for mitigating potential impacts. Such research could help resolve concerns and serve as a basis for implementing appropriate technology and procedures to accommodate increased penetration of DSGs.

Option D2: Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

Many of the problems associated with incorporating DSGs into the utility grid stem from modifications to the grid necessary to accommodate electric generation at the distribution level. Management of "two-way" power flows at the distribution level has added a new level of complexity. Some utilities have developed strategies for incorporating DSGs into economic dispatch strategies but control mechanisms for coordinating a large number of DSGs are generally not available. As the number of DSGs on a utility system increases, the complexity of this coordination becomes more difficult and the need to automate such procedures becomes more important.

Similarly, some recent research sponsored by the Electric Power Research Institute[14] indicates that conventional utility planning models may overstate the reliability benefits of load control. Developing load management systems[15] attempt to better integrate load management into hourly scheduling of resources in energy control centers. As a result, these new systems also provide better control over load management resources and, hence, more reliability benefits.

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[14] Electric Power Research Institute (EPRI), *Effect of Load Management on Reliability* (Palo Alto, CA: EPRI, July 1984), EPRI EA-3575.

[15] Such as B.F. Hastings, "The Detroit Edison Second Generation Load Management System," *Proceedings of the Institute of Electrical and Electronics Engineers (IEEE) Summer Power Meeting*, Paper No. 84-SM-559-1, July 15-20, 1984.

Appendix A
Cost and Performance Tables

Appendix A

Cost and Performance Tables

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Table A-1.—Cost and Performance of Central Station Photovoltaics

May 1985 technology status	Flat-plate	Concentrator
Level of technology development	Commercial	Commercial
Installed capacity	9.5 MWe	9.5 MWe
Reference system: general characteristics	general characteristics	
Reference year	1995	
1995 deployment level scenario	20-4,730 MWe[2]	
Plant size[3]	10 MWe[4]	
Lead-time	2 years[5]	
Land required:		
Fixed	40-90 acres[6]	
Tracking	70-370 acres[7]	60-320 acres[8]
Water required	very little[9]	
Reference system: performance parameters	performance parameters	
Operating availability	90-100%[10]	
Capacity factor[11]:		
Fixed:		
Boston	20-25%	
Miami	20-25%	
Albuquerque	25-30%	
Tracking:		
Boston	30-35%	20-25%
Miami	30-35%	20-25%
Albuquerque	35-40%	30-35%
Duty cycle	intermittent	
Lifetime[12]	10-30 years[13]	
Efficiency:		
Module:		
Boston	10-17%[14]	15-24%[15]
Miami	10-16%[14]	15-23%[15]
Albuquerque	10-16%[14]	15-23%[15]
BOS	80-85%[16]	80-85%[17]
Plant[18]	8-14%	12-20%
Reference system: costs		
Capital costs[19]:		
Modules	$100-500/sq m[20]	$100-400/sq m[21]
BOS (area dependent):		
Fixed	$50/sq m[22,23]	n/a
Tracking	$100/sq m[24,25]	$100/sq m[26,27]
BOS (power dependent)	$100-200/kWe[28]	$100-200/kWe[29]
	—————	—————
Total[30]:		
Boston	$2,000-11,000/kWe	$2,000-8,000/kWe
Miami	$1,000-9,000/kWe	$1,000-5,000/kWe
O&M costs[31]:		
Fixed	5-26 mills/kWh[32]	
Tracking	4-28 mills/kWh[33]	4-23 mills/kWh[34]

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[1] While modules of both types are at present commercially available, these differ substantially in cost and performance from those which will be on the market in 1995.

[2] The lower end of the range is the total capacity of grid-connected photovoltaic capacity which will be installed by the end of 1985. The upper end of the range coincides with the high estimate made by Pieter Bos, Polydyne, Inc., in a submission at the OTA Workshop on Solar Photovoltaic Power (Washington, DC, June 12, 1984) and discussed in Paul D. Maycock and Vic S. Sherlekar, *Photovoltaic Technology, Performance, Cost and Market Forecast to 1995: A Strategic Technology & Market Analysis* (Alexandria, VA: Photovoltaic Energy Systems, Inc., 1984), pp. 130-136.

[3] The plant rating system used here follows that used by EPRI in Roger W. Taylor, *Photovoltaic Systems Assessment: An Integrated Perspective* (Palo Alto, CA: Electric Power Research Institute, September 1983), EPRI AP-3176-SR. The plant is rated by its peak output under nominal peak operating conditions at a particular site. See footnote 30 below.

[4] The Electric Power Research Institute, see Bechtel Group, *Photovoltaic Balance of System Assessment* (Palo Alto, CA: EPRI, 1982), EPRI AP-2474. This report indicates that 5 MW subfields in central PV plants are optimum. A utility may consider a 50 to 100 MW plant, see Dan Utroska, "SMUD Forges a New Path in Photovoltaics Generation," *Electric Light and Power*, vol. 62, No. 8, August 1984, p. 21. As PV technologies other than single-crystal-silicon begin to be used, it is likely that initial plants would be in the 1 to 5 MW size range. Non-utility sponsors may undertake new capacity additions in the 5 to 10 MW range.

The plant auxiliary load other than tracking (i.e., lighting, HVAC, I&C, computer) is expected to consume less than 0.1 percent of the annual energy generated. The energy for array tracking is also insignificant because the drives use little power and operate only intermittently, see Bechtel Group, op. cit., 1982. For example, each drive in the Sacramento Municipal Utility District PV 1 plant is rated at 1/20 HP, from M. Wool, Acurex Solar Corp., personal correspondence with O. Chukumerije, Gibbs & Hill, Inc., May 1984. Consequently, the difference between gross and net plant capacity is neglected.

[5] Includes 12 to 18 months for licensing and permits. Installation at the site could be achieved at a rate of 5 to 10 MW per month. This is based on information provided in the following sources: 1) Bechtel Group, op. cit., 1982; 2) Dan Utroska, op. cit., 1984.

[6] OTA calculation. The low estimate is for Albuquerque, using a plant efficiency of 14 percent, insolation of 0.998 kWe/square meter, and a ratio of array surface/total land surface of ½. The high estimate is for Boston, using a plant efficiency of 8 percent, insolation of 0.676 kWe/square meter, and a ratio of array surface/total land surface of ½.

[7] OTA calculation. The high estimate is for Boston, assuming 5 arrays/acre, 100 square meters (net) per array, 0.676 kWe/square meter insolation, 8 percent plant efficiency. The low estimate is for Albuquerque, assuming 10 arrays/acre, 100 square meters (net) per array, 0.998 kWe/square meter insolation, 14 percent plant efficiency.

[8] OTA calculation. The high estimate is for Boston, assuming 5 arrays/acre, 100 square meters (net) per array, 0.521 kWe/square meter insolation, 12 percent plant efficiency. The low estimate is for Albuquerque, assuming 10 arrays/acre, 100 square meters of array area (net), 0.881 kWe/square meter insolation, 20 percent plant efficiency.

[9] Small amounts of water may be needed to periodically clean the module surfaces.

[10] OTA estimate. Refers to availability of the entire 10 MWe field. For information on operating availabilities, see: 1) Boeing Computer Services Co., *Photovoltaic Field Test Performance Assessment: Technology Status Report Number 3* (Palo Alto, CA: Electric Power Research Institute, November 1984), EPRI AP-3792; 2) Alexander B. Maish and Clement J. Chiang, "Photovoltaic Concentrator

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Array Reliability," *A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference, Orlando, FL, May 1-4, 1984*, Edward L. Burgess (ed.) (Albuquerque, NM: Sandia National Laboratories, 1984), SAND84-1167c, pp. 94-100.

[11] Capacity factor is defined as the ratio of actual energy produced by the plant in a year to the energy the plant could have generated if it operated continuously at its rated power. The capacity factor is a function of location. The three figures represent Boston, Miami, and Albuquerque. The high values for the fixed flat-plate arrays are taken from Taylor, op. cit., 1983, pp. 4-6; the high values for tracking-arrays were found by enhancing the fixed array data by 40 percent, as suggested by R. E. L. Tolbert and J. C. Arnett, ARCO Solar, "Design, Installation and Performance of ARCO Solar Photovoltaic Power Plants," *Proceedings of 17th IEEE Photovoltaics Specialists Conference*, Kissimmee, FL, May 1984, p. 1149; and the high concentrator values were compiled from tables from the following: 1) J. W. Doane and J. B. Gresham, Science Applications, Inc., *Photovoltaic Requirements Estimation—A Simplified Method* (Palo Alto, CA: Electric Power Research Institute, February 1983), EPRI AP-2475; 2) Gary J. Jones, Supervisor, PV Systems Development Division, Sandia National Laboratories, "A Comparison of Concentrating Collectors to Tracking Flat Panels," *A Compilation of Sandia Contributed Papers to the 17th IEEE Photovoltaic Specialists Conference, Orlando, FL, May 1-4, 1984*, Edward L. Burgess (ed.) (Albuquerque, NM and Livermore, CA: Sandia National Laboratories, June 1984), SAND84-1167c, pp. 8-13.

In all cases, the low capacity factors arbitrarily are set 5 percentage points below the high value to reflect the effects of low operating availability, dirt, and other factors other than long-term cell degradation on capacity factors.

[12] Lifetime is defined as the period in which the energy output of a plant drops by 20 percent. Ronald G. Ross, Jr., Manager, Reliability and Engineering Sciences, Flat-plate Solar Array Project, Jet Propulsion Laboratory, interview with OTA staff, Aug. 22, 1984.

[13] The low value is an extrapolation of the performance of equipment which has already been in the field for several years. Ronald G. Ross, Jr., op. cit., 1984. The high value represents DOE goals. U.S. Department of Energy (DOE), *Five Year Research Plan, 1984-1988* (Washington, DC: DOE, May 1983).

[14] These figures are based on *adjusted* estimates that modules would have efficiencies of 11 to 18 percent. The 11 percent value is from a currently commercial module. Dan Arvizu and Michael Edenburn, Sandia National Laboratories, *An Overview of Concentrator Technology*, paper presented at the Annual Meeting of the American Society of Mechanical Engineers, New Orleans, LA, December 1984. The 18 percent value represents a module efficiency based on the best laboratory silicon cell. Taylor, op. cit., 1983. The module efficiencies shown in the table result from adjusting the 11 to 18 percent range to reflect nominal peak operating conditions at each site. The methodology used is described in app. B of an Electric Power Research Institute report. Taylor, op. cit., 1983.

[15] These figures are based on *adjusted* estimates that modules would have efficiencies of 16 to 25 percent. The 16 percent value is from a currently commercial module. Arvizu and Edenburn, op. cit., 1984. The 25 percent figure is Sandia's estimate for the best commercial GaAs module in the 1990s. The module efficiencies shown in the table result from adjusting the 16 to 25 percent range to reflect nominal peak operating conditions at each site. The methodology used is described in app. B of Electric Power Research Institute. Taylor, op. cit., 1983.

[16] The low end is a Bechtel prediction. Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982 and the high end is a Sandia estimate, from Gary J. Jones, Supervisor, PV Systems Development Division, Sandia National Laboratories, Albuquerque, NM, interview with OTA Staff, August 8, 1984.

[17] The low end is a Bechtel prediction. Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982, and the high end is a Sandia estimate. Gary J. Jones, op. cit., 1984.

[18] Plant efficiency is the product of the module and the BOS efficiencies.

[19] These cost figures do not include overhead, contingency, or owner's costs.

[20] The low figure represents industry. Charles F. Gay, Vice President, Research & Development, ARCO Solar Inc., interview with OTA staff, August 10, 1984. Electric Power Research Institute, Roger Taylor, *Photovoltaic Systems Assessment: An Integrated Perspective*, op. cit., 1983, and the Department of Energy, U.S. DOE, *Five Year Research Plan, 1984-1988*, op. cit., 1983, goals. The high figure represents OTA estimates of costs of current commerial lines if they were run at larger volumes of production and used less labor.

[21] The low end represents Department of Energy, U.S. DOE, *Five Year Research Plan, 1984-1988*, op. cit., 1983, and Sandia, Dan Arvizu and Michael Edenburn, *An Overview of Concentrator Technology*, op. cit., 1984 goals. The high figure is the cost of the best currently commercial module if it were produced at 10-20MW/yr. This is based on information from 1) Juris Berzins, Intersol Power Corp., interview with OTA staff, August 10, 1984 and 2) Dan Arvizu and Michael Edenburn, *An Overview of Concentrator Technology*, op. cit., 1984.

[22] Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982.

[23] "Photovoltaic Sytems," *EPRI Journal*, vol. 9, No. 6, July/August 1984, pp. 43-45.

[24] Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982.

[25] "Photovoltaic Sytems," *EPRI Journal*, op. cit., 1984.

[26] Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982.

[27] "Photovoltaic Sytems," *EPRI Journal*, op. cit., 1984.

[28] Bechtel Group, *Photovoltaic Balance-of-System Assessment*, op. cit., 1982.

[29] Ibid.

[30] The total capital cost is given by:

cost = module cost + BOS-area cost/(module efficiency × BOS efficiency × insolation) + BOS-power costs

Nominal peak insolation and efficiency vary in different locations so that the capital costs of a given system will vary depending on where it is sited. The values given represent capital costs at *ideal sites*. In general, these costs will be higher. From Roger W. Taylor, *Photovoltaic Systems Assessment: An Integrated Perspective*, op. cit., 1984, the nominal peak insolation in several cities is:

	Total (kW/sq. m) (fixed plate)	Direct (kW/sq. m) (concentrator)
Albuquerque	0.998	0.881
Miami	0.821	0.634
Boston	0.676	0.521

Note: The total cost figures are rounded to the nearest integral multiple of a thousand.

[31] The O&M cost range used here is $2.00 to $2.50/square meter per year. This is based on estimates made in the following: 1) Jet Propulsion Laboratory, "Summary of Session VI on Array Maintenance Issue," *Proceedings of the Flat-Plate Solar Array Project Research Forum on the Design of Flat-Plate Photovoltaic Arrays for Central Stations* (Pasadena, CA: Jet Propulsion Laboratory, 1984), Dec. 5-8, 1983, Sacramento, CA, DOE/JPL-1012-98, pp. 301-304; 2) P. K. Henry, "Economic Implications of Operation and Maintenance," *Proceedings of the Flat-Plate Solar Array Project Research Forum on the Design of Flat-Plate Photovoltaic Arrays for Central Stations*, op. cit., pp. 315-316.

[32] OTA calculation. The high estimate is based on a system efficiency of 0.08, insolation of 0.676 kWe/square meter, capacity factor of 0.2, and annual O&M costs of $2.50/square meter. The low estimate is based on a system efficiency of 0.14, insolation of 0.998 kWe/square meter, capacity factor of 0.3, and annual O&M costs of $2.00/square meter.

[33] OTA calculation. The high estimate is based on a system efficiency of 0.08, insolation of 0.676 kWe/square meter, capacity factor of 0.3, and annual O&M costs of $2.50/square meter. The low estimate is based on a system efficiency of 0.14, insolation of 0.998 kWe/square meter, capacity factor of 0.4, and annual O&M costs of $2.00/square meter.

[34] OTA calculation. The high estimate is based on a system efficiency of 0.12, insolation of 0.521 kWe/square meter, capacity factor of 0.2, and annual O&M costs of $2.50/square meter. The low estimate is based on a system efficiency of 0.20, insolation of 0.881 kWe/square meter, capacity factor of 0.35, and annual O&M costs of $2.00/square meter.

Table A-2a.—Cost and Performance of Solar Thermal-Electric Plants Parabolic Dishes (Mounted-Engine)

May 1985 technology status

Level of technology development: demonstration units in operation
Installed capacity: 0.075 MWe[1]
Reference system: general characteristics
Reference year: 1995
Deployment level scenario:[2]
  High . . . . 200 MWe
  Medium . . . . 100 MWe
  Low . . . . 0.4 MWe
Plant size: 10.8 MWe (gross) (400 units @ 27.1 kWe (gross))[3] 10.2 MWe (net) (400 units @ 25.6 (kWe net))
Lead-time: 2 years[4]
Land required: 67 acres[5]
Water required: negligible[6]
Reference system: performance parameters
Operating availability: 95 percent[7]
Duty cycle: intermittent
Capacity factor: 20-35 percent[8]
Plant lifetime: 30 years[3]
Plant efficiency: 20-25 percent[10]
Reference system: costs
Capital costs: $2,000-3,000/kWe (net)[11]
O&M costs: 15-53 mills/kWh[12]

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[1] This includes three 25 kWe parabolic dish units.

[2] Deployment scenarios depend heavily on whether or not the currently provided Renewable Energy Tax Credit is extended beyond the end of 1985, and whether the federal government subsidizes installations in any other way. The low scenario assumes that the only additions to currently installed capacity will be: 1) two 25 kWe parabolic dish installations now being constructed under the McDonnell Douglas Astronautics Co.'s Dish/Stirling Program, 2) four additional parabolic dish installations expected under the McDonnell Douglas Astronautics Co.'s Dish/Stirling Program, 3) 100 kWe at the federally sponsored Osage City, KS, Small Community Experiment #1, and 4) 100 kWe at the federally sponsored Molokai, HI, demonstration project. Under favorable conditions (e.g., with an extension of the RTC), however, hundreds of MWe may be installed by 1995; see Nina Markov, "Exciting Developments Reflect Bright Future," *Renewable Energy News*, vol. 7, No. 2, May 1984, pp. 8-12. An upper limit of 200 MWe will be used here; the medium deployment scenario will is half that figure, or 100 MWe.

[3] Based on Advanco Corp.'s Vanguard I module, at direct insolation levels of 1,000 watts/square meter, ambient air temperatures of 28° C, wind speed of 2.2 m/s (5mph); see Byron J. Washom, et al., *Vanguard I Solar Parabolic Dish-Stirling Engine Module* (Palm Springs, CA: Advanco Corp., 1984), final report summary of work performed under Department of Energy cooperative agreement DE-FC04-82AL16333, May 28, 1982-Sept. 30, 1984, DOE-AL-16333-2 (84-ADV-5), p. 142.

[4] And design and 1 year of construction.

[5] Ibid. Based on six modules per acre.

[6] Ibid.

[7] Figure for individual module availability. Based on information provided by: 1) OTA contractor N. Hinsey, Gibbs & Hill, Inc., interviews with James E. Rogan, Manager, Market Development, McDonnell Douglas Astronautics Corp., July 16 and Aug. 13, 1984; 2) Byron J. Washom, President, Advanco Corp., personal correspondence with OTA staff, Nov. 9, 1984; 3) Advanco Corp., *Proposal to the U.S. DOE Relating to the Small Community Solar Experiment at Molokai, Hawaii* (Palm Springs, CA: Advanco, 1984).

[8] The range provided here is identical to that used for the photovoltaic concentrator modules. See Footnote 11 of the photovoltaics cost and performance table (table A-1) for an explanation of the capacity factor used there. Within this range fall estimates from the following sources: 1) James H. Nourse, Branch Manager, McDonnell Douglas Corp., personal correspondence with OTA staff, Nov. 1, 1984; 2) Byron J. Washom, President, Advanco Corp., personal correspondence with OTA staff, Nov. 9, 1984. Washom indicated that a facility located at Barstow, CA, would have an annual capacity factor of 25.7 percent; 3) Byron J. Washom, et al., *Vanguard I Solar Parabolic Dish-Stirling Engine Module*, op. cit., 1984; 4) Tony K. Fung, Senior Research Engineer, Southern California Edison, comments on OTA draft report, April 1985.

[9] OTA contractor N. Hinsey, Gibbs & Hill, Inc., interviews with James E. Rogan, op. cit., 1984.

[10] Washom, op. cit., Nov. 9, 1984. Annual average efficiency at Barstow, CA, would be about 23 percent.

[11] Based on information provided by: 1) OTA contractor N. Hinsey, Gibbs & Hill, Inc., interviews with Don H. Ross, Director, Energy Systems Center, Sanders Associates, Inc., July 11 and 16, 1984; 2) OTA contractor N. Hinsey, Gibbs & Hill, Inc., interviews with James E. Rogan, op. cit., 1984; 3) James H. Nourse, Branch Manager, McDonnell Douglas Corp., personal correspondence with OTA staff, Nov. 1, 1984; 4) Byron J. Washom, President, Advanco Corp., personal correspondence with OTA staff, Nov. 9, 1984.

Advanco reportedly estimates that mass produced Stirling/dish units would cost approximately $2,300/kWe; see "SCE's 'A/R' Program Rediscovers a Solar Thermal Power Technology—The Parabolic Dish . . . ," *SCE R&D Newsletter*, vol. 13, No. 1, 1st Quarter 1984, pp. 1-2.

[12] OTA figure, based on information obtained from McDonnell Douglas and Advanco Corp.; see Byron J. Washom, et al., *Vanguard I Solar Parabolic Dish-Stirling Engine Module*, op. cit., 1984; and Advanco Corp., *Proposal to the U.S. DOE Relating to the Small Community Solar Experiment at Molokai, Hawaii*, op. cit., 1984. The O&M cost for a commercial module would be $1,600/year and average annual module net output would be 56,234 kWh. This amounts to 28 mills/kWh, a figure within the lower end of the OTA range.

[11] The capital cost for this plant varies most importantly with the cost of the heliostats, which here are assumed to 42 percent of total plant costs. This coincides roughly with estimates made by the California Energy Commission, the Electric Power Research Institute, and Teknekron Research, Inc.; California Energy Commission, *Appendices, Technical Assessment Manual*, op. cit., 1984.

Heliostat costs are especially sensitive to the number of heliostats produced. Using extremely optimistic assumptions about heliostat production levels, a Sandia study suggested that heliostat costs would vary between $100 and $150 per square meter of heliostat (1980$) if 520,000 heliostats were produced over an 11 year period; see H. F. Norris, Jr., and S. S. White, Manufacturing and Cost Analyses of Heliostats Based on the Second-Generation Heliostat Development Study (Livermore, CA: Sandia National Laboratories, n.d.), DE83006664. If a single 100 MWe plant requires about 15,400 heliostats, that is enough heliostats for nearly 34 installations of 100 Mwe each. The report suggests that if production were scaled down to half that number (about 17 installations over an 11 year period), the costs per square meter of heliostat could increase 4 to 14 percent. If the larger increase (14 percent) in heliostat cost is applied to the original costs per square meter, one obtains a range of $114 to $171 per square meter of heliostats (1980$). If a 100 MWe installation requires 663,000 square meters of heliostats, this amounts to $756 to $1,134 per kWe (1980$); this averages out to $945 per kWe (1980$) if enough heliostats for 17 100-MWe plants are sold.

For this to occur, the construction of a heliostat plant would have to be initiated no later than 1992, as an initial production facility would take 3 years to build. A fully automated factory would have to be initiated even earlier than that. The manufacturer would have to have assurance that high rates of production could continue beyond the end of the century (from McDonnell Douglas, Response by McDonnell Douglas, "General Workshop Discussion Questions . . ." submitted to OTA in response to written questions submitted in connection with OTA workshop on Solar Thermal Electric Technologies, 1984). It is highly unlikely that this quantity of orders would be expected to support production over the decade beginning in 1995.

Heliostat costs probably therefore might be considerably higher for the few commercial units which are completed in the latter half of the 1990s. However, while low production levels might drive costs higher, technical improvements alone may drive heliostat costs downward as much as 25 percent; see California Energy Commission, *Technical Assessment Manual*, op. cit., 1984. As a rough approximation, it is assumed here that the two opposite effects on heliostat costs roughly cancel each other out.

If the heliostat cost represents 42 percent of total plant costs, then total plant costs would be $2,250/kWe (1980$). Using the producer price index, this yields about $2,531 in 1983 dollars, or $2,500 rounded-off. This figure is based mostly on optimistic assumptions for 1995, and therefore will be used as the low end of the OTA cost range for 1995.

The high end of the range assumes that heliostats will cost $250 per square meter (1983$), the present estimated cost for heliostats. This is based on information from the following sources: 1) Personal correspondence between A. Skinrood, Sandia National Laboratories, Livermore, CA, and N. Hinsey, Gibbs & Hill, Inc., May 11, 1984; 2) Nina Markov, "Exciting Developments Reflect Bright Future," Renewable Energy News, vol. 7, No. 2, May, 1984, pp. 8-12.

If 663,000 square meters are required for a 100 MWe plant, the price of the heliostats is approximately $1,658/kWe. If this represents about 53 percent of plant costs, then total capital costs would be $3,108/kWe. This table will use the rounded figure of $3,100/kWe as the high end of the cost range. This is somewhat lower than the $3,616/kWe (1983$) used in a 1984 analysis by the Solar Energy Industries Association to represent the costs of building three central receiver plants (30 MWe, 60 MWe and 100 MWe) between 1985 and 1992. And it is considerably lower than the $4,000/kWe figure cited in one source (Markov, op. cit., 1984) as being the present cost of central receivers, as estimated by "industry analysts."

Several published estimates for commercial units fall within the lower bounds of OTA range. The California Energy Commission uses a construction cost estimate in 1982 dollars of $2,580 (about $2,606 in 1983 dollars) for a 1990 central receiver system with the capacity to store 3 hours-worth of power, and to operate with a capacity factor of 40 percent; see California Energy Commission, op. cit., 1984. EPRI estimates a similar figure for a 1992 central receiver; see EPRI, *Technology Assessment Guide*, op. cit., 1982.

It should be noted these earlier estimates assume mass production of heliostats, in numbers sufficient to allow heliostat costs to drop to relatively low levels. It is here assumed that mass production of heliostats will not immediately follow the startup of the first 100 MWe commercial demonstration unit, and that the heliostats utilized by any commercial units which begin operation in the 1990s will utilize heliostats manufactured in relatively small batches at costs as high as $250/square meter, yielding plant costs of about $3,100/kWe. Fortifying this estimate is the fact that Solar One cost about $16,060/kWe (1983$), and the projected installed cost for SoCal Ed's proposed (and cancelled) 100 Mwe unit was about $6,000/kWe (1983$); see California Energy Commission, *Technical Assessment Manual*, op. cit., 1984.

[12] Based on information from the following sources: 1) Battleson, op. cit., 1981; 2) OTA Workshop on Solar Thermal-Electric Generating Technologies, op. cit., 1984.

Based on 42 percent capacity factor (escalated to 1983$). O&M costs could be reduced with the installation of central control facilities and roving operators (from OTA contractor N. Hinsey, Gibbs & Hill, Inc., interview with J. Bigger, Electric Power Research Institute, May 10, 1984). However, a pool of several plants is necessary to operate on such a basis. This will most likely not be the case in 1995. Therefore, O&M costs are not expected to drop significantly until many plants are on-line.

E. Weber indicates a 12.4 mill/kWh O&M cost for a 60-MW plant with a 23 percent capacity factor; see E. Weber, "Financial Requirements for Solar Central Receiver Plants" (Phoenix, AZ: Arizona Public Service Co., 1983).

This is considerably higher than the estimate provided by Teknekron Research, Inc., Energy and Environmental Systems Division, *Draft: Cost Estimates and Cost Forecasting Methodologies for Selected Nonconventional Electrical Generation Technologies*, submitted to Technology Assessments Project Office, California Energy Commission, May 1982. This report estimated that annual O&M for a 100 MWe plant would be $1,166,000 (1978$). Assuming a 42 percent capacity factor, this amounts to 4.6 mills/kWh (1983$). The figure, however, is lower than would be obtained if another source's estimate of annual O&M of $5.6 million/year (1981$) for a 100 MWe plant is used; see J. R. Roland, and K. M. Ross, "Solar Central Receiver Technology Development and Economics—100 MW Utility Plant Conceptual Engineering Study," op. cit., 1983. That figure, with a 42 percent capacity factor, would yield about 16 mills/kWh in 1983$.

Table A-2b.—Cost and Performance of Solar Thermal-Electric Plants Central Receivers[1]

May 1985 technology status

Level of technology development: concept supported by small pilot facility[2]
Installed capacity: 10.8 MWe[3]
Reference system: general characteristics
Reference year: 1995
Deployment level scenario:[4]
  High . . . . 110 MW
  Medium . . . . 60 MWe
  Low . . . . 10 Mwe
Plant size:[5]
  Gross: 110 MWe
  Net: 100 MWe
Lead-time, years: 5[6]
Land required: 700 acres[7]
Water required: 0.7 million gallons/day[8]
Reference system: performance parameters
Operating availability: 90-95 percent[9]
Capacity factor: 42 percent[10]
Duty cycle: intermediate
Plant lifetime: 30 years[11]
Plant efficiency: 20-25 percent[12]
Reference system: costs
Capital costs for commercial unit: $2,500-3,100/kWe (net)[13]
O&M costs: 10-12 mills/kWh[14]

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[1] The system referred to here is a molten salt central receiver. This presently is the preferred variety of central receiver among major proponents.

[2] The pilot facility referred to here is Solar One, a receiver which uses water to absorb the Sun's heat; no such electricity-producing pilot facility exists for the molten salt variety of central receiver. However, Sandia National Laboratories in New Mexico operate a Molten Salt Electric Experiment (MSEE) which began operating in 1984. It can produce 750 kWe.

[3] This figure represents the 10.8 MWe Solar One central receiver. While it is not a molten salt receiver, it is included here because it is in many ways very similar to a molten salt central receiver.

[4] The low scenario assumes that no central receivers other than Solar One (10 MWe) will be operating by 1995. The medium scenario assumes that a 50 MWe molten salt pilot plant begins operating by that time. The high scenario assumes in addition that a 100 MWe commercial demonstration is unit is operating by the end of 1995.

[5] commercial receivers are expected to be as large as 200 to 500 MWth. T. Tracey, *Development of a Solar Thermal Central Heat Receiver Using Molten Salt* (Denver, CO: Martin Marietta, 1982). (At a nominal efficiency of 25 percent, the electric generation range is 50 to 125 MWe.) Receiver development and investigation has been performed by Babcock & Wilcox and Martin Marietta in the 100 MWe plant size range; this also was selected as the reference size used by the Electric Power Research Institute in its Technical Assessment Guide. See the following sources: 1) Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR; 2) O. Durrant, *The Development and Design of Steam/Water Solar Receivers for Commercial Application* (New York: Babcock & Wilcox Co., 1982); 3) S. Wu, et al., *Conceptual Design of an Advanced Water/Steam Receiver for a Solar Thermal Central Power System* (Livingston, NJ: Foster Wheeler Development Corp., 1982).

In the OTA's Solar Thermal Electric Power Workshop, June 12, 1984, Charles Finch of McDonnell Douglas indicated that the gross capacity of a plant should be 110 MW if it is to yield 100 MW net.

It should be noted that industry observers foresee an initial development of 30 to 50 MW modular demonstration units. Subsequent commercial units could possibly be multiples of 50 MW plants. This is based on information from: 1) E. Weber, Arizona Public Service, personal correspondence with N. Hinsey, Gibbs & Hill, Inc., May 10, 1984; 2) A. Skinrood, Sandia National Laboratories, personal correspondence with N. Hinsey, Gibbs & Hill, Inc., May 11, 1984.

[6] Two years of preconstruction, licensing, and design and 3 years of construction; see Electric Power Research Institute, *Technical Assessment Guide*, op. cit., 1982; and K. Battleson, *Solar Power Tower Design Guide: Solar Thermal Central Reciever Power Systems, A Source of Electricity and/or Process Heat* (Albuquerque, NM: Sandia National Labs, April 1981), SAND81-8005. The latter report estimates 4 years but does not include permitting and licensing.

California Energy Commission (CEC), Technology Assessments Project Office, *Appendices: Technical Assessment Manual* (Sacramento, CA: CEC, 1984), vol. I, 3rd ed. This source estimates a lead-time of 8 years; it includes time for advance planning (1 year), regulatory (2 years), purchase orders (1 year) and construction and start-up (4 years).

[7] Based on approximately 0.53 acres/million Btu/hr for a plant with a capacity factor of 42 percent and 2850 kWh/sq m-yr insolation; see Battleson, op. cit., 1981.

In one source, Arizona Public Service Co., "Responses to Questions Pertaining to Solar Thermal Electric Power Plants for the Office of Technology Assessment's New Generating Technology Cost and Performance Workshop," June 1984, it was estimated that about 8.4 acres per MWe would be required for a central receiver system; this would amount to 840 acres for a 100 MWe plant.

[8] "The water requirements for a solar plant would be essentially the same as those for a water-cooled fossil-powered utility plant. There would be a small incremental water requirement for washing heliostats (5,000 gal/yr per MWth peak)." Battleson, op. cit., 1981. Water requirements for a conventional power plant are 675 gal/hr/MW; see K. Yeagar, *Fluidized Bed Combustion—An Evolutionary Improvement in Electric Power Generation*, vol. 1, August 1980, USDOE CONF-80048. This corresponds to 680,400 gal/day for a plant with 42 percent capacity factor. This figure added to 5,000 gal/day for washing heliostats (380 MWth + 100 MWe) yields 685,400 gal/day.

[9] Based on information from the following sources: 1) N. Hinsey, Gibbs & Hill, Inc., OTA contractor, interview with E. Weber, Arizona Public Service, May 10, 1984; 2) N. Hinsey of Gibbs & Hill, Inc., OTA contractor, interview with A. Skinrood, Sandia National Laboratories, Livermore, CA, May 11, 1984; 3) U.S. Congress, Office of Technology Assessment, Workshop on Solar Thermal-Electric Generating Technologies, Washington, DC, June 12, 1984.

Availability must be 90 percent or greater, especially for an intermediate duty unit, to be seriously considered by utilities. D. Van Atta, "Israeli Solar Plant Blooms," *Engineering News Record*, vol. 211, No. 21, Nov. 24, 1983. This figure is supported by: J. R. Roland and K. M. Ross, "Solar Central Receiver Technology Development and Economics—100 MW Utility Plant Conceptual Engineering Study," *Energy Technology X: A Decade of Progress*, Richard F. Hill (ed.) (Rockville, MD: Government Institutes, Inc., 1983), pp. 1421-1444.

[10] From Gibbs & Hill, Inc., *Overview and Evaluation of New and Conventional Electrical Generating Technologies for the 1990s*, OTA contractor report, 1984. Actual capacity factors will vary considerably depending on system design, location, and operating practices.

The California Energy Commission in a 1984 report assumes a 40 percent capacity factor for a unit with 3 hours' worth of storage. For the same amount of storage, EPRI assumes a capacity factor of 30 percent and Teknekron Research, Inc., assumes a capacity factor of 50 percent; see Electric Power Research Institute, *Technology Assessment Guide*, op. cit., 1982; and Teknekron Research, Inc., *Cost Estimates and Cost Forecasting Methodologies for Selected Nonconventional Electrical Generation Technologies* (Sacramento, CA: CEC, 1982), CEC Report No. P300-300-82-006.

[11] Based on information in the following sources: 1) Battleson, op. cit., 1981; 2) N. Hinsey, Gibbs & Hill, Inc., OTA contractor, interview with J. Bigger, Electric Power Research Institute, May 10, 1984; 3) E. Weber, *Financial Requirements for Solar Central Receiver Plants* (Phoenix, AZ: Arizona Public Service Co., 1983).

[12] From Gibbs & Hill, Inc., *Overview and Evaluation of New and Conventional Electrical Generating Technologies for the 1990s*, op. cit., 1984.

Table A-3.—Cost and Performance of Medium-Sized Wind Turbines

May 1985 technology status

Level of technology development[1]: commercial
Installed capacity: 650+ MWe[2]
Reference system: general characteristics
Reference year[3]: 1995
Deployment level scenario[4]:
  High ....2,900 MWe
  Medium .....2,200 MWe
  Low ....1,500 MWe
Plant size (no. of units x unit nameplate capacity):
  50 turbines @ 400 kWe[5]
Lead-time: 1-2 years[6]
Land required: 300-2000 acres[7]
Water required: negligible
Reference system: performance parameters
Availability: 95-98[8]
Duty cycle: intermittent
Plant lifetime: 20-30 years[9]
Capacity factor:[10]
  High ....85 percent
  Medium .....30 percent
  Low ....20 percent
Reference system: costs
Capital costs: $900-1,200/kWe (net)[11].
O&M costs: 6-14 mills/kWh[12]

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[1] Almost all of the commercially operating units in 1984 were small wind turbines, rather than the medium-sized units expected to dominate in the 1990s.

[2] Thomas A. Gray, Executive Director, American Wind Energy Association, personal correspondence with OTA staff, Jan. 29 and May 6, 1985. Gray estimated that 550 MWe were in place in California and that approximately 100 MWe were in place elsewhere in the United States at the end of 1984. It is not known how much additional capacity was installed during the first 4 months of 1985.

[3] The reference year 1995 is selected as being the year for which wind turbine cost and performance will best typify the cost and performance of turbines during the 1990s.

[4] In estimating the low range, it is assumed that: a) an additional 400 MWe will be installed in California in 1985, and b) the sum of the capacities installed from 1985-95 in California and from 1983-95 in the rest of the country is equal to 400 MWe. This low estimate essentially assumes a boom and bust situation where high levels of tax-subsidized investment through the end of 1985 is followed by a period of very low—though continued—growth over the following decade. The high range assumes: a) that the 1,450 MWe projected by the California Energy Commission to be on-line in California by 1996, and b) an equivalent amount of wind power will be installed elsewhere in the country by that time; see Thomas Tanton, California Energy Commission (CEC), "Memo to Interested Parties: Background Material for Nov. 2, 1984, CEC workshop on Resource Estimates of Small Power Technologies in California" (Sacramento, CA: CEC, Oct. 26, 1984). The medium deployment level is roughly halfway between the high and the low.

[5] Units in sizes ranging from 200 to 600 MWe are being actively developed and may be deployed before the end of 1985. See: 1) Tanton, op. cit., 1984; 2) Robert Lynette, R. Lynette & Associates, Inc., personal correspondence with OTA staff, Dec. 5, 1984; 3) "Westinghouse Nearing Final Agreement on Selling 15 600-kWe Windmills to HEI," *Solar Intelligence Report*, Dec. 24, 1984, p. 406; 4) Tom Gray, Executive Director, American Wind Energy Association, personal correspondence with OTA staff, November 1984.

[6] This assumes that the pre-construction period is 6 months to 1 year, and that the construction period is 6 months to 1 year as well. Based on information provided by: 1) OTA workshop on Wind Power, June 12, 1984, Washington, DC; 2) Lynette, op. cit., 1984.

[7] Based on information provided by Donald A. Bain, Wind Energy Specialist, Oregon Department of Energy, personal correspondence with OTA staff, June 11, 1985. The low estimate assumes a power density of 15 acres/MWe based on a turbine spacing of 3 rotor diameters on each side and 6 rotor diameters in front and behind each turbine. The high estimate assumes a power density of 80 acres/MWe based on a turbine spacing of 10 rotor diameters on each side as well as in front and behind.

[8] Based on information provided by: 1) Lynette, op. cit., 1984; he stated that current reliable units are averaged 95 percent reliability in 1984; he suggests a range of 92 to 97 for intermediate sizes in the 1990s. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, vol. 9, No. 9, November 1984, pp. 44-46. This source indicates that an availability of 70 to 96 percent has been achieved with small turbines and that availabilities could reach 95 to 96. It cautions, however, that it is not clear what capital costs would be associated with that range of availabilities. 3) Bain, op. cit., 1985. He expects availability to be 98 percent.

[9] Based on information from the following: 1) Lynette, op. cit., 1984. He estimated that the lifetime will be 20 to 30 years. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, op. cit.; this article assumes a lifetime of key wind turbine components is 20 to 30 years. EPRI does, however, acknowledge that this is a key assumption that has "not yet been adequately tested in operational systems because of insufficient field experience." 3) Bain, op. cit., 1985. He indicated that the lifetime of windfarms would be 20 to 30 years.

[10] This range generally corresponds with average wind speeds of 14 to 18 mph. Higher average wind speeds will yield higher capacity factors, all other things being equal. This is in rough accordance with the following estimates: 1) The California Energy Commission's 22 to 35 percent range used in an analysis of wind-generated electricity cost; see Tanton, op. cit., 1984. 2) A figure of 30 percent estimated by The Southern California Edison Co. for the projected mature technology; from I.R. Straughan, Southern California Edison Co., "R&D Input to the Fall 1984 Generation Resource Plan," unpublished memorandum, Aug. 30, 1984. 3) A figure of 30 percent provided by Lynette, op. cit., 1984 is used as the medium-range figure. 4) The 35 percent figure was considered reasonable by participants in OTA's Workshop on the Cost and Performance of Wind Turbines, June 7, 1984, Washington, DC.

[11] Based on information provided by: 1) Panelists attending OTA's Workshop on the Cost and Performance of Wind Turbines, June 7, 1984, Washington, DC, who felt that the cost could go below $1,000 by 1990. 2) Lynette, op. cit., 1984. He suggested it could go below $1,000 in 2 to 3 years. By 1995, costs presumably could drop still further. 3) Charles R. Imbrecht, chairman of the CEC, stated in mid-1984 that turbine costs should drop to $950/kWe by the year 2000; see *Solar Energy Intelligence Report*, June 18, 1984, p. 199. 4) Straughan, op. cit., 1984; this memo indicates that the projected mature technology would be characterized by total direct costs of $1,175/kWe (1985$).

Donald A. Bain, Oregon Department of Energy, personal correspondence with OTA staff, June 11, 1985; he indicated that wind farms could be installed today at a cost of $1,330/kWe, and that the OTA estimate may be too high.

[12] This is based on information from the following: 1) Lynette, op. cit., 1984. 2) "Wind Turbine Operating Experience and Trends," *EPRI Journal*, November 1984, pp. 44-46; this article indicates that O&M costs of 7 to 10 mills/kWh (1984$) are possible with small machines. 3) Straughan, op. cit., 1984; he suggests that the "projected mature technology" would be characterized by first year O&M costs of $22/kWe (1985$) for a wind farm of 10 MWe operating with a 30 percent capacity factor. This amounts to 8.4 mills/kWh (1983$).

Table A-4.—Cost and Performance of Geothermal Technologies

May 1985 technology status	Dual flash	Binary[1] Large/small
Level of technology development	Commercial experience overseas; first commercial unit in U.S. to operate in 1985[2]	Large: demo plant under construction/Small: commercial units operating[3]
Installed capacity (gross)	none[4]	none/22.3 MWe
Reference system: general characteristics		
Reference year	1995	1995/1995
1995 deployment-level scenario (dual-flash and binary only)[5]:		
High	1,166-1,830 MWe[6]	
Medium	406-1,165 MWe[7]	
Low	122-405 MWe[8]	
Plant size (number of units x unit size):		
Gross, MWe	1 x 53[9]	1 x 70[10]/2 x 5[11]
Net, MWe	1 x 50	1 x 50/2 x 3.5
Lead-time, years	3-5[12]	3-5/1[13]
Land required, acres	8-20[14]	8-20/1-3[15]
Water required, gals/day	3 million[16]	4.1 million[17] /0.6 million[18]
Reference system: performance parameters		
Operating availability, percent	85-90[19]	85-90/85-90[20]
Duty	Base[21]	Base/Base[22]
Unit lifetime, years	30[23]	30/30[24]
Plant efficiency (watt-hours/lb of steam)[25]:	7.0-8.0[26]	9.5-12.0/7.0-9.0[27]
Reference system: costs		
Capital costs, $/kWe (net)	1,300-1,600[28]	1,500-1,800[29]/ 1,500-2,000[30]
O&M costs, mills/kWh:	10-15[31]	10-15[32]
Fuel (brine) costs, mills/kWh[33]:	20-70	20-70

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[1] Two scales of binary technology are included. Although large binary geothermal plants will benefit from economies of scale, smaller modular, wellhead units will also be deployed. Smaller 5 to 10 MWe modular units will allow the progressive development of a geothermal resource. This approach lessens the initial upfront dedication of capital and allows for demonstration of the resource. Module sizes of 10 MWe for flash units are most likely the smallest to be developed due to limitations in turbine design; from R. Walter and N. Hinsey, Gibbs & Hill, Inc., personal correspondence with OTA staff, May 7 and June 26, 1984.

[2] Geothermal dual flash technology is considered commercial today; see W. Collins, *Proceedings of the Geothermal Program Review II* (Washington, DC: U.S. Department of Energy, December 1983), CONF-8310177. Nearly 400 MWe of dual flash generated electricity was installed worldwide by the end of 1983; see R. DiPippo, "Worldwide Geothermal Power Development," *Geothermal Resources Council Bulletin*, vol. 13, No. 1, January 1984. The first U.S. unit is expected to operate commercially in 1985.

[3] The larger binary cycle plants will have their first demonstration when a 45 MWe plant operates in 1985 at Heber, CA. Small units are already operating at several locations in the U.S.

[4] Although no dual flash units are presently operating in the U.S., a 30 MWe unit has been operating since 1981 at Cerro Prieto, Mexico, 50 km south of California. An additional 440 MWe (four 110 MWe units) of dual flash capacity is expected to be on-line this year in the same vicinity. The first U.S. dual flash unit (47 MWe) is under construction at Heber; see DiPippo, op. cit., 1984.

[5] Since the most recent and comprehensive estimates referenced make no distinction between binary and dual flash plants, a single set of deployment values are projected.

[6] From the Electric Power Research Institute's Utility Geothermal Survey's "possible" estimate of U.S. geothermal electricity power capacity in 1995; see P. Kruger and V. Roberts, "Utility Industry Estimates of Geothermal Energy," *Geothermal Resources Council Transactions*, vol. 7, October 1983, pp. 25-29. Estimate has been corrected to exclude 2,680 MWe expected at The Geysers in 1995; see T. Cassel, et al., *National Forecast for Geothermal Resources Exploration and Development* (Washington, DC: U.S. Department of Energy, March 1982), DOE/ET/27/242-T2.

[7] Kruger and Roberts, op. cit., 1983. Estimate has been corrected to exclude 2,680 MWe expected at The Geysers in 1995; see Cassel, et al., op. cit., 1982.

[8] The low end of the range represents the total generating capacity (dual-flash and binary only) now installed or under construction. The high end of the range is derived from Kruger and Roberts, op. cit., 1983. This figure has been corrected to exclude 1,753 MWe of capacity at The Geysers either operating, under construction, planned, or a speculative addition; see DiPippo, op. cit., 1984.

[9] An EPRI Utility Geothermal Survey indicated that nearly 60 percent of respondents consider 50 MWe to be the minimum size for a commercial plant. With regard to optimum size commercial plants, two-thirds indicated a preference for 100 MWe and one-third for 50 MWe; see V. Roberts, "Utility Industry Estimates of Geothermal Electricity," *Geothermal Resources Council Bulletin*, vol. 11, No. 5, May 1982, pp. 7-10. California regulations require that electric generating facilities greater than 50 MWe (net) file for certification and also perform a documentation of the resource and technology. To date, all geothermal plants planned or under construction (excluding The Geysers) in California do not exceed 49 MWe (net) in order to avoid the delay and cost of complying with regulations for units larger than 50 MWe (net). Since most geothermal development is expected to occur in California in the next 5 to 10 years, 50 MWe appears to be a reasonable size for the reference plant discussed here. This is based on information provided by: 1) Walter and Hinsey, op. cit., 1984; 2) R. DiPippo, Southeastern Massachusetts University, personal correspondence with N. Hinsey, Gibbs & Hill, Inc., May 7, 1984; 3) Collins, op. cit., 1983.

Gross plant size shown (53 MWe) represents that of a dual flash system.

[10] Same rationale as in footnote 9. Binary cycles require much more auxiliary power to pump brine and would need a 70 MWe turbine (size reduction would occur as efficiency of the cycle is improved); see DiPippo, op. cit., 1984.

[11] Several observers have projected that modular, wellhead units will comprise a large portion of binary development at lower temperature, less understood resources: 1) Jack S. Wood, Wood & Associates, personal correspondence with OTA staff, Oct. 6, 1984; 2) Evan Hughes, Electric Power Research Institute, personal communication with OTA staff, Oct. 4, 1984; 3) Janos Laszlo, Senior Mechanical Engineer, Pacific Gas & Electric, personal communication with OTA staff, Oct. 10, 1984.

The 5 MWe unit corresponds to a powerplant geared to the output of one well; from Ben Holt, Ben Holt Co., personal communication with OTA staff, Sept. 10, 1984.

[12] Great variations may result from licensing requirements, about which there is considerable uncertainty. The first unit at a given site will take longer, possibly 5 years due to initial permitting and licensing. Subsequent units could require as little as 3 years. Based on information provided by: 1) OTA, Workshop on Geothermal Power, Washington, DC, June 5, 1984; 2) Cassel, et al., op. cit., 1982.

[13] For large units see footnote 13. Smaller units can be factory fabricated and shipped to the site much quicker than larger units. Modular units, depending on the site, could be brought on-line in as few as 6 months (not including permitting and licensing). Jack S. Wood, Wood & Associates, personal communication with OTA staff, Oct. 6, 1984, indicated that it takes only 100 days to full operation after a modular unit arrives onsite. Inclusion of licensing and permitting should extend lead-time to 1 year. Great variations may result from licensing requirements, about which there is considerable uncertainty.

[14] OTA Workshop on Geothermal Power, op. cit., 1984. This value does not include the entire area of the field because much of the land above the field can still be utilized and only part of the surface is occupied by the facilities. (Modular units would be at the low end of this range.)

[15] The larger units should require up to 20 acres—similar to dual flash units; from Walter and Hinsey, op. cit., 1984. A smaller unit can vary from less than 1 acre for a modular, container-mounted unit to 3 acres for a unit similar to an East Mesa, CA unit; see Gibbs & Hill, Inc., *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s*, OTA contractor report, Sept. 13, 1984.

[16] Based on an estimate made by J. A. Bickerstaffe, Gibbs & Hill, Inc., personal correspondence with OTA staff, May 1, 1985, he estimated that the 47 MWe (net) Heber dual flash unit will require approximately 2,800 gallons/minute of make-up water. This figure was adjusted for the slightly larger 50 MWe (net) reference plant, operating with a capacity factor of 70 percent. The figure

assumes that all steam condensate is reinjected with the spent brine. If any of the condensate is used for cooling purposes, make-up water requirements will be smaller.

[17] Based on estimate that the 45 MWe (net) Heber Binary plant will consume water at a rate of 3,700 gallons per minute. The water requirement was estimated by Southern California Edison Co. in comments made on OTA draft cost and performance tables, Apr. 10, 1985. This was adjusted for the slightly larger 50 MWe (net) reference plant, operating with a capacity factor of 70 percent.

[18] Based on estimate made by Zri Krieger of Ormat Turbines. Mr. Krieger stated that a 20 MWe (net) installation consisting of 26 modules planned for East Mesa, CA, would have make-up water requirements of about 1,500 to 1,800 gallons/minute. This was adjusted for the considerably smaller 7 MWe (net) reference plant, operating with a capacity factor of 70 percent.

[19] OTA Workshop on Geothermal Power, op. cit., 1984.

[20] Ibid.

[21] Ibid.

[22] Ibid.

[23] Design life of current plants is 30 years. This is not expected to change in the next 10 years; from Walter and Hinsey, op. cit., 1984.

[24] OTA Workshop on Geothermal Power, op. cit., 1984.

[25] Evaluated at a 400° F resource.

[26] Figures shown represent "net brine effectiveness" (defined as watts of net electric power output per pound per hour geothermal flow) in w-hr/lb. For current state-of-the-art power systems the net brine effectiveness ranges from 7.0 to 8.0 for dual flash cycles, respectively, given a resource temperature of 200° C (400° F); see T. Cassel, C. Amundsen, and P. Blair, *Geothermal Power Plant R&D: An Analysis of Cost-Performance Trade-offs and the Heber Binary Cycle Demonstration Project* (Washington, DC: U.S. Department of Energy, June 30, 1983), DOE/CS/30674-2. Dual flash is a mature technology and basic cycle efficiency improvements are not expected as with conventional cycles; gains in efficiency can be achieved through greater capital and operating expenditures. Economic considerations, as opposed to technical breakthroughs, drive these decisions; see Gibbs & Hill, Inc., op. cit., 1984.

[27] Figures shown for high, medium, and low represent "net brine effectiveness" (defined as watts of net electric power output per pound per hour geothermal flow) in w-hr/lb. For current state-of-the-art power systems the net brine effectiveness is about 9.5 for binary cycles, respectively, given a resource temperature of 200° C (400° F); see Cassel, Amundsen, and Blair, op. cit., 1983. Reference 10 reveals that an advanced binary system (utilizing a countercurrent condensor and a recuperator) brine effectiveness could reach 11.9 for a 200° C resources with 2,000 to 100,000 ppm total dissolved solids, with additional penetration. Binary cycle research indicates that there will be improvements in brine effectiveness as more work is performed on direct contact heat exchangers, staged heat rejection, recuperation and counter-current condensing. Twelve w-hr/lb represents the estimated maximum probable net effectiveness; see J. Whitbeck, Idaho National Engineering Lab, "Heat Cycle Research Program," *Proceedings of the Geothermal Program Review II* (Washington, DC: U.S. Department of Energy, December 1983), CONF-831077. The smaller binary plants are not as efficient as their larger counterparts. With significant penetration, net effectiveness could increase to 9 w-hr/lb; from H. Ram, Ormat, Inc., personal communication with OTA staff, Oct. 6, 1984.

[28] Based on information from: 1) Walter and Hinsey, op. cit., 1984; 2) OTA Workshop on Geothermal Power, op. cit., 1984; 3) Cassel, Amundsen, and Blair, op. cit., 1983.

Capital costs are not expected to decrease as a function of on-line capacity. Small, modular, flash units (approximately 10MWe) cost $1,500 to 1,600/kWe for single units (based on data from Gibbs & Hill, San Jose Office). When several units are purchased together the cost could be as low as $1,000/kWe; from Walter and Hinsey, op. cit., 1984. Installations at highly saline resources will be more costly, however.

[29] Based on information from the following sources: 1) Walter and Hinsey, op. cit., 1984; 2) OTA Workshop on Geothermal Power, op. cit., 1984; 3) Gibbs & Hill, Inc., op. cit., 1984.

Capital costs are not expected to increase as more units are deployed. Large binary plants will have larger capital costs because of the greater complexity involved.

[30] The smaller binary plants will have higher capital costs than large binary cycle plants. Costs of $2,000/kWe have been reported for a 7 MWe (net) plant; from Holt, op. cit., 1984. Very small 5 MWe, containerized, binary units have been advertized for $1,500/kWe, installed; from Ram, op. cit., 1984.

[31] OTA Workshop on Geothermal Power, op. cit., 1984. O&M costs of plants now in operation vary widely due to the qualities of the resouces being utilized. The Heber flash plant has an O&M cost of 10.3 mills/kWh and could be considered average. Advances in operation, including computerized controls and roving operators, could reduce the operating component of O&M costs somewhat in the next 10 years. But this improvement would not be significant when compared to the possible range of total O&M costs; see Walter and Hinsey, op. cit., 1984.

[32] O&M costs are expected to be the same as those of the dual flash technology. Based on information provided by: 1) Walter and Hinsey, op. cit., 1984; 2) OTA Workshop on Geothermal Power, op. cit., 1984.

[33] OTA Workshop on Geothermal Power, op. cit., 1984. Brine costs result from negotiation with the brine supplier. The brine cost will tend towards a price which causes the total cost of the geothermal plant to be competitive with the least expensive alternative form of base load generation. Depending on location, this could vary between 20 to 70 mills/kWh; see P. Blair, T. Cassel and R. Edelstein, *Geothermal Energy: Investment Decisions and Commercial Development* (New York: Wiley Interscience, 1982).

Table A-5.—Cost and Performance of Large Atmospheric Fluidized-Bed Combustion Systems[1]

May 1985 technology status

Level of technology development: commercial demonstration unit under construction[2]

Installed capacity (large units only): none

Reference-system: general characteristics

Reference year: 1990

U.S. deployment level scenario, 1990 (large units only, including retrofit units):[3]

- High . . . . .735 MWe
- Medium . . . . . . .610 MWe
- Low . . . . .510 MWe

Plant size (no. of units x unit size):

- Gross . . . . .1 x 163 MWe
- Net . . . . . . .1 x 150 MWe

Lead-time: 5-10 years[4]

Land required: 90-218 acres[5]

Water required: 1.5 million gallons/day[6]

Reference system: performance parameters

Availability: 85-87 percent[7]

Duty cycle: base/intermediate

Plant lifetime: 30 years

Plant efficiency: 35 percent[8]

Reference system: costs

Capital costs: $1,260-1,580/kWe[9]

O&M costs: 7.66 mills/kWh[10]

Fuel costs: 17.4 mills/kWh[11]

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[1] Unless otherwise specified, the figures relate to entirely new "grass roots" electric powerplants, not to the retrofits of fluidized bed combustors to existing power plants. Also, unless otherwise stated, the figures apply only to plants designed and operated to produce electric power only; cogenerators are excluded.

[2] Note that three large retrofit units are under construction. Two of these are utility demonstration units; one is a commercial nonutility unit.

[3] The deployment figures include both entirely new plants and retrofits. All deployment levels assume that the following plants will have been completed and will be operating by 1990:

—Tennesee Valley Authority Shawnee Unit 160 MWe, to be completed 1989

—Colorodo Ute, Nucla unit, 100 MWe, to be completed 1987 (retrofit)

—Northern States Power Co., Black Dog Unit 2, 125 MWe, to be completed 1986 (retrofit)

—Florida Crushed Stone Co., Brookesville, FL, 125 MWe, to be completed 1987 (retrofit, cogeneration)

The low scenario assumes that no plants other than those listed above will be operating in 1990. The high scenario assumes that two additional retrofit unit will be operating with a total additional capacity of 225 MWe and the medium scenario assumes that one additional 100 MWe units will be operating. Neither the medium nor the high scenarios are expected, only the low one is.

[4] It is assumed that the AFBC will have roughly the same lead-time as the IGCC. This assumes 3 to 5 year preconstruction period and a 2 to 5 year construction period. Exceptionally favorable circumstances could lead to lead-times below this range; unusually poor conditions to result in a higher lead-time.

[5] Using a figure of 0.6 to 1.45 acres/MWe. The land estimate includes the land required for solid waste disposal and coal storage. This figure is based on two sources: 1) Battelle, Columbus Division, *Final Report on Alternative Generation Technologies*, vols. I and II (Columbus, OH: Battelle, 1983). This source indicated that a 1,000 MWe plant would require 1,450 acres; this averages out to 1.45 acres/MWe. 2) Kurt E. Yeager, Electric Power Research Institute, "Coal Utilization in the U.S.—Progress and Pitfalls," *Proceedings of the Sixth International Conference on Coal Research*, London, UK, Oct. 4, 1982 (London, UK: National Coal Board, 1982), pp. 639-664. This source suggests that 1,200 acres would be required for a 1,000 MWe plant; this averages out to 1.2 acres/MWe. 3) James W. Bass, III, Project Engineer, AFBC Technical Services, TVA, personal correspondence with OTA staff, Apr. 30, 1985. He estimated that the TVA 160 MWe demonstration plant will occupy approximately 93 acres. This amounts to about 0.6 acres/MWe.

[6] Based on an estimate that an AFBC would consume approximately 0.6 gallons per kWh and a capacity factor of 0.7, see Yeager, op. cit., 1982. These figures are consistent with estimates made by Bass, op. cit., 1985.

[7] Based on information provided by: 1) Workshop on Fluidized-Bed Combustors, OTA, Washington, DC, June 6, 1984. 2) Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: EPRI, May 1982), P-2410-SR. 3) Stratos Tavoulareas, Project Manager, Fluidized Combustion, Coal Combustion Systems Division, EPRI, personal correspondence with OTA staff, Feb. 19, 1985.

[8] Based on information provided in the following sources: 1) K.E. Yeager, "Fluidized Bed Combustion—An Evolutionary Improvement in Electric Power Generation," *The Proceedings of the Sixth International Conference on Fluidized-Bed Combustion*, Apr. 9-11, vol. 1, 1980, CONF-800428. 2) "EPRI, B & W Score Major Advance with Atmospheric Fluidized Bed Boiler," *The Energy Daily*, Oct. 10, 1979. 3) Burns and Roe, *Conceptual Design of a Gulf Coast Lignite-Fired Atmospheric Fluidized-Bed Power Plant* (Palo Alto, CA: Electric Power Research Institute, 1979), EPRI EP-1173. 4) R. Smock, "Utilities Look to Fluid Bed Design as Next Step in Boiler Design," *Electric Light and Power*, vol. 62, No. 7, July 1984, pp. 27-29. 5) Yeager, op. cit., 1982. This source suggests that a 1,000 MWe unit would have an efficiency of 35.3 percent.

[9] The high end of the range is based on an estimate made by Tavoulareas, op. cit., May 15, 1985. He estimated that the costs, in 1984 dollars, might be approximately $1,640/kWe for a plant with a net capacity of 193.3 MWe (209.6 MWe gross). Converted to 1983 dollars using the Handy Whitman Bulletin Cost Index (see Definitions section of this apppendix), this yields $1,580/kWe. This is considered the high range of the OTA estimate. The low end of the range is set 20 percent lower than that figure, or $1,260.

[10] This is based on an estimate made by Tavoulareas, op. cit., 1985. He estimated that the O&M costs, in 1984 dollars, might be approximately 7.96 mills/kWh for a plant with a net capacity of 193.3 MWe (209.6 MWe gross). Converted to 1983 dollars using the Handy Whitman Bulletin Cost Index (see Definitions section), this yields an O&M cost of 7.66 mills/kWh.

[11] Based on a 1990 coal cost of $1.78/million Btu (see details in the Definitions section of this appendix for an explanation for fuel costs) and an average annual heat rate of 9,751 Btu/kWh.

Table A-6.—Cost and Performance of Integrated Gasification/Combined-Cycle Powerplants[1]

May 1985 technology status

Level of technology development: demonstration plant
Installed capacity: 100 MWe
Reference system: general characteristics
Reference year: 1990
Deployment level scenario: 200 MWe[2]
Plant size: 500 MWe (net)[3]
Lead-time: 5-10 years[4]
Land required : 300-600 acres[5]
Water required : 3-5 million gallons/day[6]
Reference system: performance parameters
Operating availability: 85 percent[7]
Duty cycle: base
Plant lifetime: 30 years[8]
Plant efficiency: 35-40 percent[9]
Reference system: costs
Estimated capital cost, 1990: $1,200-1,350/kWe[10]
O&M costs, 1990: 6-12 mills/kWh[11]
Fuel costs, 1990: 15-17 mills/kWh[12]

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[1] The performance and cost data presented in this table are expected to bracket the various gasification technologies used in IGCC plants. Workshop on IGCC, OTA, Washington, DC, June 6, 1984.

[2] It is assumed that by 1990, two IGCCs will have operated in the United States: the 100 MWe Cool Water plant and the Dow Chemical Co. plant in Plaquemine, LA, the capacity of which will be 100 MWe or more.

[3] The plant auxiliary power requirements will vary between 10 and 16 percent of net output depending on the design; see Fluor Engineers, Inc., *Cost and Performance for Commercial Applications of Texaco-Based Gasification-Combined-Cycle Plants*, vols. 1 and 2 (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI AP-3486; and Argonne National Laboratory (ANL) and Bechtel Group, Inc., *Design of Advanced Fossil Fuel Systems (DAFFS): A Study of Three Developing Technologies for Coal-Fired, Base-Load Electric Power Generation*, summary report (Chicago, IL: ANL, 1983), ANL/FE-83-9. By far the greatest portion of the power (roughly 3/4 of parasitic power requirements) is required to run the oxygen plant.

[4] This assumes a preconstruction, licensing and design period of 2 to 5 years and a construction lead-time of 3 to 5 years.

The lower end of the estimate is the design potential of the IGCC. In general, if great care is taken during construction and early operation, and close cooperation with regulatory authorities is pursued, the 5-year lead-time could be achieved. If these steps are not taken, however, for the first few plants, the complexity and uncertainty inherent in any new technology will cause the lead-times to extend to as much as 10 years.

Overall lead-time estimates have been made by: 1) Peter Schaub, Manager, New Technology Program, Potomac Electric Power Co. (PEPCO), personal correspondence with OTA staff, Feb. 1, 1985. He suggested that 10 years was a reasonable estimate. This view was supported by Steven M. Scherer, Senior Project Engineer, PEPCO, personal correspondence with OTA staff, May 23, 1985. PEPCO is likely to be one of the first utilities to commit to building an IGCC. Feasibility studies for an IGCC had been initiated by April 1985; the entire installation is not expected to be on-line until 1997. 2) The California Energy Commission estimates that the lead-time would be 9.5 years and the L.A. Department of Water and Power which estimates that the lead-time would be 10 years; see California Energy Commission, *Technical Assessment Manual*, vol. I, Edition II, Appendices (Sacramento, CA: CEC, June 1984), p. B-3. 3) The participants at the OTA Workshop on the IGCC, op. cit., 1984, who endorsed an 8 to 10 year estimate.

Preconstruction, licensing, and design period estimates have made by: 1) Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR. This source estimates that preconstruction, licensing and design for an IGCC would take 4 years. The analogous period for the Cool Water was nearly 4 years: February 1978 to December 1981. 2) S. Sessions, U.S. Environmental Protection Agency, Acting Director, Regulatory Policy Division, Office of Policy Analysis, personal correspondence with OTA staff, Feb. 1, 1985. Mr. Sessions suggested that 4 to 5 years was not an unreasonable estimate for a typical IGCC being licensed over the next 10 years, particularly in view of the relative inexperience with the technology which will characterize the applicants and the regulators.

Thomas L. Reed of Southern California Edison, stated in personal correspondence with OTA staff, May 24, 1985, that the California site-selection process for the Cool Water facility took 18 months and that the licensing period also took 18 months, for a total of 3 years. Mr. Reed also stated that the site-selection process is an ongoing process that does not have to await a plant commitment before it is initiated. He therefore thought that 6 months would be a typical period for the site-selection process and that as a result the total preconstruction period would be only 2 years.

Construction period estimates have been made by: 1) EPRI, op. cit., 1982. This source estimates that construction lead-times for an IGCC would be approximately 3 years. 2) Schaub, op. cit., 1985. Mr. Schaub suggested that 3 to 5 years was a reasonable estimate. This estimate was confirmed by Scherer, op. cit., 1985. 3) Reed, op. cit., 1985. Mr. Reed estimated that construction would take 3 years. However, he saw no reason why the period would be longer than 3 years. 4) Michael Gluckman, EPRI, personal correspondence with OTA staff, June 12, 1985; he estimated 2 to 3 years. However, like Tom Reed, he does not believe a plant could take longer than 3 years to build unless extraordinary problems arise.

Note that the selected range is lower than the estimated 68 month lead-time typical of U.S. coal plants which began operating in 1976; see Applied Decision Analysis, Inc., *An Analysis of Power Plant Construction Lead Times*, Vol. 1: Analysis and Results (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EA-2880.

The Cool Water plant was characterized by a construction lead-time (from initial construction to beginning of the demonstration period) of less than 3 years. The plant however was characterized by circumstances which are unlike those expected of a commercial plant. Some of these characteristics tended to lengthen the lead-time, others to shorten it. The evidence used in making the OTA estimate suggests that early commercial plants will take longer to build. An important reason for this is the fact that commercial plants are currently projected to be much larger than the Cool Water plant.

[5] See ANL and Bechtel, op. cit., 1983; this report indicates that about 400 acres are required for plant, access and interim onsite disposal with 110 to 140 additional acres for off-site permanent disposal. Also see Fluor Engineers, op. cit., 1984; this study shows that about 260 acres are required for the plant including storage for 30 years worth of ash. The differences probably result from differences in coal quality, plant rating, and layout criteria for the buffer zone. Hence a range of 300 to 500 acres is shown in the table.

[6] See Fluor Engineers, op. cit., 1984; this report indicates 6 to 7 gpm/MWe water would be required depending on the method by which the gas is cooled. See also ANL and Bechtel, op. cit., 1983; this report indicates 8 to 10 gpm/MWe. Based on 6 to 10 gpm/MWe, a plant size of 500 MWe and a 0.7 capacity factor, 3 to 5 million gallons/day would be required.

[7] EPRI, op. cit., 1982, indicates that an operating availability of 89 percent and equivalent availability of 81 percent is likely. See also Fluor Engineers, op. cit., 1984; this report indicates that IGCC plants can be designed for equivalent availabilities in the 80 to 85 percent range.

[8] EPRI, op. cit., 1982.

[9] Fluor Engineers, op. cit., 1984; this report suggests efficiencies of 34.4, 36.2, and 37.9 percent for total quench, radiant only and radiant plus convective Texaco designs. The ANL/Bechtel study, op. cit., 1983, indicates 36.9, 37.5, and 39.5 percent efficiencies for Texaco, BGC Lurgi, and Westinghouse designs. Hence a range of 35 to 40 percent is used here. This range is in rough accordance with the 35 to 39 percent estimate made by B.M. Banda et al., "Comparison of Integrated Coal Gasification Combined Cycle Power Plants with Current and Advanced Gas Turbines," *Advanced Energy Systems—Their Role in our Future*, Proceedings of 19th Intersociety Energy Conversion Engineering Conference, August 19-24, 1984, San Francisco, CA (U.S.: American Nuclear Society, 1984), paper 849507, pp. 2404-2407.

[10] Fluor Engineers, Inc., op. cit., 1983, this report gives $/kWe costs of 957, 998, and 1061 for total quench, radiant only and radiant plus convective Texaco designs. These costs do not include contingency costs. Based on a 20 percent contingency allowance (versus 17 to 19 percent used in the Fluor study) and Handy Whittman Index Ratio of 242/233, a 1,200 to 1,350 $/kWe range is shown in the table. The ANL/Bechtel report, op. cit., 1983, mentions comparable (January 1980) costs of $1,030/kWe (BGC/Lurgi) and $1,252/kWe (Texaco).

[11] The following estimates fall within this range: 1) ANL and Bechtel, op. cit., 1983. The study indicates that O&M costs would be in the 10.8 to 11.5 mills/kWh range (January 1980 dollars and 67 percent capacity factor). 2) Synthetic Fuels Associates, Inc., *Coal Gasification Systems: A Guide to Status, Applications, and Economics* (Palo Alto, CA: Electric Power Research Institute, June, 1983), EPRI AP-3109; the study shows O&M costs (for 1,000 MWe plant) to be 5 to 6 mills/kWh (mid-1982$). 3) D. F. Spencer, Vice President, Advanced Power Systems Division, Electric Power Research Institute, personal correspondence with OTA staff, May 17, 1985. Mr. Spencer estimated that O&M costs would be 6 to 8 mills/kwh.

[12] Based on 8,533 to 9,751 Btu/kWh heat rate (equivalent to 35 to 40 percent efficiency) and 1990 coal costs of $1.78/MM Btu (see Definitions section of this appendix for an explanation of fuel costs).

Table A-7.—Cost and Performance of Fuel Cell Powerplants[1]

May 1985 technology status	Large	Small
Level of technology development[2]:	Demonstration units planned	Demonstration units operating[3]
Installed capacity:	none	1.5 MWe[4]
Reference system: general characteristics		
Reference year: 1995		
Deployment level scenario:[5]		
High . . . . 800-1,200 MWe		
Medium . . . . 400-600 MWe		
Low . . . . 40 MWe		
Plant size (number of units x unit size):[6]		
Gross	1 x 11.5 MWe	2 x 200 kWe
Net	1 x 11.0 MWe	2 x 200 kWe
Lead-time[7]	3-5 years	2 years
Land required	0.5 acres[8]	480-600 sq. ft[9]
Water required[10] [11]	negligible	
Reference system: performance parameters		
Operating availability[12]	80-90 percent	
Duty cycle	Variable	Variable
Plant lifetime[13]	30 years	20 years
Plant efficiency[14]	40-44 percent[15]	36-40 percent[16]
Reference system: costs		
Capital costs:	$700-$3,000/ kWe[17]	$950-$3,000[18]
O&M costs (mills/kWh):[19]		
Base/Cogen (75 percent c.f.)	4.2-11.5	4.2-11.5
Intermediate (40 percent c.f.)	4.2-11.3	4.2-11.3
Peaking (10 percent c.f.)	4.3-10.7	4.3-10.7
Fuel costs (mills/kWh)[20]	27-30	30-33

[1] Only phosphoric acid fuel cells are considered.

[2] In 1983, no commercial-scale demonstration units were operating in the United States. In 1984 the first of a series of about fifty 40-kWe units were operating in the United States, and a 4.5 MWe facility was operating in Japan. Further demonstration units are planned for the next five years, in a variety of sizes, both in Japan and in the United States.

[3] These units are 40 kWe, and are substantially different in design from the larger units (with capacities of several hundred kWe) expected to be commercially deployed in the 1990s.

[4] This consists of 38 units rated at 40 kWe each.

[5] The low estimate assumes that approximately fifty 40-kWe (net) units, two 11-MWe units, and two 7.5-MWe powerplants will have been installed by 1995. All would be demonstration units, some of which will cease operation before 1995. The low scenario assumes that no commercial units will be operating in 1995.

The medium scenario assumes the following: 1) The bulk of initial orders will be for large fuel cell powerplants rather than small ones. 2) Investors will not initiate commercial fuel-cell projects until they have seen demonstration units operating for a year. 3) Large commercial demonstration units will go into service in 1988-89, and investors will initiate projects no sooner than 1989-90. 4) Demonstration and commercial projects will have lead-times of 3 years; the commercial projects therefore would not yield operating generating capacity until 1992-93. 5) Beginning in 1992-93, an average of 200 MWe of fuel cell powerplants will be placed in operation each year through 1995. This deployment level is considered by industry sources to be the minimum level which allows the economic production of fuel cells in one manufacturing facility. This is equivalent to the startup of about eighteen 11 MWe plants each year.

This results in a deployment scenario of 400 to 600 MWe (absorbing all of the fuel cells produced in 2 to 3 years from a single manufacturing facility). This is equivalent to between thirty-six and fifty-five 11 MW units, though in actuality the installations would vary in size.

The high scenario is based on assumptions (1) through (4) above. Assumption (5) however is changed to an average deployment level of 400 MWe annually from 1992-93 through 1995—double the deployment levels assumed in the medium scenario. This results in a deployment level in 1995 of 800 to 1,200 MWe. This deployment level could be met by expanding the fuel-cell output of a single manufacturing plant, or by operating more than one manufacturing plant. Under this scenario, the equivalent of thirty-six, 11 MWe plants would be started up each year, starting in 1992 or 1993; a total of 73 to 109 such plants would be operating by mid-1995 under this scenario.

[6] The small fuel cell installations deployed in the 1990s likely will be built around two or more stacks each capable of delivering 200 kWe (net) AC. It is assumed that two stacks would be used in the reference plant, but several more might be deployed at any one site. It is assumed that the large fuel cell installations in the 1990s will be built around stacks each capable of generating 250 to 700 kWe (DC). Installation capacity probably would range from several megawatts and up. The installation assumed here would consist of approximately 18 stacks, each capable of generating 675 kWe (DC). While larger or somewhat smaller installations are likely to be built and operated, their cost and performance should roughly coincide with that of the 11 MWe plants.

[7] The lower estimate for the large fuel cell installation is based on discussions at OTA Workshop on Fuel Cells, Washington, DC, June 6, 1984. The upper estimate for the large plant is based on estimates made by California Energy Commission, *Technical Assessment Manual*, vol. I, Edition III (Sacramento, CA: CEC, 1984), P300-84-013, and by OTA staff. The greatest uncertainty in the range results primarily from uncertainty regarding regulatory delays. Many of the fuel cell installations are likely to be deployed in areas where little previous powerplant development has occurred, and where population densities increase the possibilities for regulatory conflicts. The potential for regulatory problems was exemplified by a 4.5 MWe demonstration unit which was built (but never operated) in New York City. Numerous unanticipated regulatory delays were encountered, and prevented the expeditious completion of the plant; approval of the project by New York City's fire department took 3 years.

The estimate for the small fuel cell installation is based on discussions at OTA Workshop on Fuel Cells, op. cit., 1984. The extremely small size of the plant suggests that regulatory delays would be considerably less problematic than would be the case with larger plants. Some within the industry believe that lead-times could be as short as several months; see R.A. Thompson, Manager, Business Planning, United Technologies Corp., Fuel Cell Operations, personal correspondence with OTA staff, Feb. 15, 1985.

[8] Burns & McDonnell Engineering Co., *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EM-3512. See also comments of Thompson, op. cit., 1984.

[9] OTA estimate based on two modules, each measuring 30 x 8 feet. This is the size of module suggested by Richard R. Woods, Jr., Manager, Fuel Cells, Gas Research Institute, in personal correspondence with OTA staff, Feb. 4, 1985.

[10] United Technologies Corp., *Specification for Dispersed Fuel Cell Generator*, Interim Report (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EM-2123, Project 1777-1.

[11] United Technologies Corp., Power Systems Division, *Onsite 40-kilowatt Fuel Cell Power Plant Model Specification*, prepared for U.S. Department of Energy and the Gas Research Institute (South Windsor, CT: United Technologies, September 1979), FCS-1460.

[12] This is based on Fuel Cell Users Group, System Planning Subcommittee, Ad Hoc Reliability Task Force, *Report on Fuel Cell Reliability Assessment* (Washington, DC: Fuel Cell Users Group, March 1983). The report recommended use of an 85 percent availability factor in system planning studies for large fuel cell powerplant installations. It however stated that availability could range between 80 and 88 percent, depending on assumptions made about component redundancy and about the availability of spare parts. It is assumed that the operating availabilities of small fuel cell powerplants will fall within the same range as that of the larger fuel cells, as no comparable studies are available on the operating availabilities of the small plants.

[13] This refers to the plant lifetime. Cell stacks themselves are assumed to have lifetimes of 40,000 hours when running at full capacity.

[14] This is the operating efficiency at which electricity is produced when the plant is operated at its full rated capacity. In cogeneration applications, where useful heat will be produced along with electric power, the total energy efficiency (which includes all useful energy outputs, thermal and electric) would be much higher. The cogeneration efficiency could be as high as 85 percent.

[15] Based on higher heating value of fuel. This range is consistent with estimates made in numerous sources, including: 1) United Technologies Corp., *Specification for Dispersed Fuel Cell Generator*, Interim Report (Palo Alto, CA: Electric Power Research Institute, 1981), EPRI EM-2123, Project 1777-1. 2) Mike Ringer, California Energy Commission, *Relative Cost of Electricity Production* (Sacramento, CA: CEC, December 1983). 3) "Utilities Show Interest in Large Fuel Cell Installations for Late '80s," *Electric Light and Power*, vol. 62, No. 6, June 84, p. 53. 4) Irwin Stambler, "Fuel Cell Outlook Brightens as Technical Obstacles Fall," *Research & Development*, December 84, pp. 50-53. 5) Battelle, Columbus Division, *Final Report on Alternative Generation Technologies*, vols. I and II (Columbus, OH: Battelle, 1983). 6) Thompson, op. cit., 1985.

[16] Based on higher heating value of fuel. From: 1) J.W. Staniunas and G.P. Merten and R.M. Smith, United Technologies Corp., *Follow-On 40-kWe Field Test Support*, Annual Report, prepared for Gas Research Institute (Chicago, IL: Gas Research Institute, 1984), FCR-6494, GRI-84/0131. 2) Woods, op. cit., Feb. 4, 1985.

[17] Estimates do not include cell replacement costs. The lower end of the range assumes a mature technology and mass production; the high end of the range represents the estimated cost of the commercial demonstration units expected to be installed and operated in the late 1980s. Within this range fall the estimates cited in the following: 1) The participants in an OTA Workshop on Fuel Cells, op. cit., 1984. 2) Ringer, op. cit., 1983. 3) California Energy Commission, op. cit., 1984. 4) I.R. Straughn, Southern California Edison Co., "R & D Input to the Fall 1984 Generation Resource Plan," unpublished memorandum, August 1984. 5) Lee Catalano, "Can Fuel Cells Survive the Free Market in the 1990's?" *Power*, vol. 128, No. 2, February 1984, pp. 61-63. 6) Burns & McDonnell Engineering Co., *System Planner's Guide for Evaluating Phosphoric Acid Fuel Cell Power Plants* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EM-3512. 7) Battelle, op. cit., 1983. 8) J.R. Lance et al., Westinghouse Electric Corp., "Economics and Performance of Utility Fuel Cell Power Plants," *Advanced Energy Systems—Their Role in Our Future*, Proceedings of 19th Intersociety Energy Conversion Engineering Conference, Aug. 19-24, 1984, San Francisco, CA (U.S.: American Nuclear Society, 1984), paper 849133, pp. 821-826.

Where a single "expected" value is used in this report, a value of $1,430/kWe is used.

[18] The estimates do not include cell replacement costs. The lower end of the range assumes a mature technology and mass production; the high end of the range represents the estimated cost of the first commercial cogeneration units. Within this range fall the estimates cited in the following: 1) Richard Woods, Gas Research Institute, as quoted in: Ernest Raia, "Fuel Cells Spark Utilities Interest," *High Technology*, vol. 4, No. 12, December 1984, pp. 52-57. 2) Catalano, op. cit., 1984. 3) OTA Workshop on Fuel Cells, op. cit., 1984. 4) Thompson, op. cit., 1985.

As an *expected* value for capital costs, OTA uses in its analysis a value of $2,240 (1983 $). This is based on an estimate made by the Gas Research Institute (GRI) of the cost of a 200 kWe cogeneration module; see Stephen D. Ban, GRI, *Gas-Fueled Cogeneration—GRI's Current R&D Program*, unpublished mimeograph (Washington, DC: GRI, n.d.). The GRI estimate referred to the expected costs during the period of early market entry, with low-quantity fuel-cell production levels.

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[19] Total O&M costs include fixed O&M costs, variable O&M costs and stack replacement costs. This study assumes fixed O&M costs of $2.00 to $5.00/kWe-year and variable O&M costs of 2 to 5 mills/kWh. These estimates of fixed and variable O&M costs appear to be in accord with information provided in the following documents: 1) Ringer, op. cit., 1983. 2) Straughn, op. cit., 1984. 3) Burns & McDonnell Engineering Co., op. cit., 1984. 4) Battelle, op. cit., 1983.

Estimates made in the above sources do not appear to include stack replacement costs; these are rarely estimated in the literature. Evidence available to OTA suggests that these will range between $100 and $300/kWe, depending especially on fuel-cell production levels at the time the replacements are made. It is assumed that fuel cells are replaced after 40,000 hours of operation at full capacity. The replacement cost estimates are levelized values over 30 years, using a 5 percent discount rate.

Total O&M costs estimates consequently are as follows (mills/kWh):

Duty Cycle	*Fixed*	*Variable*	*Replacement*	*Total*
Base/Cogen	0.3-0.8	2-5	1.9-5.7	4.2-11.5
Intermediate	0.6-1.4	2-5	1.6-4.9	4.2-11.3
Peaking	2.3-5.7	2-5	-0-	4.3-10.7

Under the assumption that fuel cells would have to be replaced every 40,000 hours at full capacity operating levels, no replacement stacks would be required for a peaking powerplant.

[20] Based on 1995 natural gas price of $4.40/mm Btu (see Definitions section of this appendix for an explanation of assumed fuel costs), and a heat rate of 8,533 to 9,481 Btu/kWh (36 to 40 percent efficiency) for small fuel cell plants and 7,757 to 8,533 Btu/kWh (40 to 44 percent efficiency) for large fuel cell plants.

Table A-8.—Cost and Performance of Compressed Air Energy Storage Plants

May 1985 technology status	Maxi-CAES	Mini-CAES
Level of technology development[1]:	No U.S. demos./ 2 demo. plants overseas	
Installed capacity[2]	-0-	-0-
Reference system: general characteristics		
Reference year: 1990		
Plant size[3]	220 MWe	50 MWe
1990 deployment level scenario	-0-	0-100 MWe[4]
Lead-time[5]	5-8 years	4.5-6.5 years
Land required	15 acres[6]	3 acres[7]
Water required	360,000 gals/ day[8]	100,000 gals/ day[9]
Reference system: performance parameters		
Operating availability:	90-98	percent[10]
Duty cycle: peaking to intermediate[11]		
Plant lifetime: 30 years[12]		
Plant efficiency:		
Fuel (Btu/kWh)	4000[13]	4000[14]
Electricity (kWh-in/kWh-out)	0.78[15]	0.78[16]
Electricity out/ (Fuel + Electricity in)[17]	0.51	0.51
Discharge/charge[18]	4-10 hours	16-8 hours[19]
Reference system: costs		
Capital costs:		
Above-ground equipment	$515/kWe[20]	$392/kWe
Below-ground equipment:		
Aquifer	$50/kWe[21]	$48/kWe
Salt	$55/kWe[22]	$95/kWe
Rock	$85/kWe[23]	$441/kWe
Total	$565-600/ kWe	$487-833/kWe[24]
O&M costs: 3.6 mills/kWh[25]		
Fuel costs:		
Fuel:		28 mills/kWh
Electricity:		16-35 mills/kWh
Total:		42-63 mills/kWh[26]

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[1] A 290 MWe salt dome based CAES plant is operating in Huntorf, West Germany. Another smaller 25 MWe plant just has been completed in Italy. Neither, however, has ever been demonstrated in the United States.

[2] No capacity in the United States has been installed. One project sponsored by Soyland Power cooperative was scheduled for commercial operation in 1986. However, it was canceled in 1983.

[3] Brown Boveri currently offers plant equipment for 50, 100, 220, and 300 MWe applications; from Z. Stanley Stys, Vice President, BBC Brown Boveri, Inc., personal correspondence with Fred Clements, Gibbs & Hill, Inc., May 9, 1984. The following two references selected 200 MWe as a typical size: 1) Electric Power Research Institute, *Compressed Air Energy Storage: Commercialization Potential* (Palo Alto, CA: EPRI, 1982), EM-7750. 2) Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR.

However, since then, EPRI commissioned a study on mini CAES plants; see Gibbs & Hill Inc., *Mini Compressed Air Energy Storage Systems (25 MWe, 50 MWe modules)*, draft report submitted to EPRI (New York: Gibbs & Hill, Inc., April 1984); the report indicates that mini CAES plants in the 25 to 100 MWe range are also economically viable and can compete with the larger 220 and 300 MWe plants. The mini CAES plants use proven equipment in modular configurations and require shorter lead-time.

[4] The low end of the estimate assumes no plants are completed by 1990. The high end assumes two mini-CAES plants are completed by that time.

[5] Based on information from the following: 1) Construction time of 3 to 4 years for maxi-CAES and 2.5 years for mini-CAES, from Robert B. Schainker, Electric Power Research Institute, and Michael Nakhamkin, Gibbs & Hill Inc., "Compressed-Air Energy Storage (CAES): Overview, Performance and Cost Data for 25MWe-220MWe Plants," *IEEE Power Engineering Review*, April 1985, pp. 32-33. 2) Licensing time of 2 to 4 years. The low estimate is provided by Schainker and Nakhamkin, op. cit., 1985. The high estimate was obtained from Peter Schaub, Manager, New Technology Program, Potomac Electric Power Co., personal correspondence with OTA staff, November 1984.

[6] Gibbs & Hill Inc., *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s*, OTA contractor report, 1984, calculated for a plant using a salt cavern.

[7] Gibbs & Hill Inc., op. cit., April, 1984. Calculated for a plant using a salt cavern.

[8] Hans Christoph Herbst, NWK, and Z. Stanley Stys, Vice President, BBC Brown Boveri, Inc., *Huntorf 290-MWe, the World's First Air Storage System Energy Transfer (Asset) Plant: Construction and Commissioning*. Presented to American Power Conference, Chicago, IL, Apr. 24-26, 1978. Downsized for typical 220 MWe plant, calculated for a plant using a salt cavern. Note that CAES plants can be designed to use no water at all, from Robert B. Schainker, EPRI, personal correspondence with OTA staff, May 28, 1985.

[9] Gibbs & Hill Inc., op. cit., April 1984, calculated for a plant using a salt cavern.

[10] With respect to maxi-CAES, see Robert B. Schainker, EPRI, and M. Nakhamkin, Gibbs & Hill Inc., *Compressed-Air Energy Storage: Overview, Performance, and Cost Data for 25MWe to 220Mwe Plants*, paper prepared for the Joint Power Generation Conference, October 1984, Toronto, Canada. That paper states that the Huntorf, West Germany, plant has 90 percent availability; the availability for the last reporting period was 98 percent—Stys, op. cit., May 1984. For mini-CAES, operating availability is expected to be at the high end of the range; this is supported by information provided by: 1) Gibbs & Hill Inc., op. cit., 1984. 2) Schainker and Nakhamkin, op. cit., October 1984.

[11] Gibbs & Hill Inc., op. cit., 1984.

[12] The estimate for maxi-CAES is based on information provided by EPRI, *Compressed Air Energy Storage: Commercialization Potential*, op. cit., 1982. The estimate for maxi-CAES is based on information provided by Gibbs & Hill Inc., op. cit., April 1984.

[13] Schainker and Nakhamkin, op. cit., October 1984.

[14] Robert B. Schainker, EPRI, in a personal correspondence with OTA staff, May 28, 1985, indicated that mini-CAES would have the same fuel efficiency as maxi-CAES.

[15] Schainker and Nakhamkin, op. cit., October 1984.

[16] Schainker, op. cit., May 28, 1985, indicated that mini-CAES would have the same electricity efficiency as maxi-CAES.

[17] This calculation assumes that for every kWh (3,413 Btu) generated, 4,000 Btu of fuel and 2,662 Btu of electricity are required. Thus, the efficiency is 3,413/6,662 or 51 percent. This calculation does not consider the efficiency losses associated with the electric power supplied to the CAES plant.

[18] A CAES plant does not need to charge and discharge at the same power. Thus a plant which discharges 220 MWe for 4 hours can charge with 43 MWe for 16 hours. In general, the power needed to charge a CAES plant which will discharge at full power for T0 hours is:

Power-in = (aMWe x T0)/(T1 x 0.78)

where T1 is the charge time, 0.78 is the kWh-in/kWh-out efficiency, and a is the capacity rating of the CAES plant.

[19] The Huntorf plant has a 4 hour/16 hour discharge/charge cycle; see Peter Maass and Z. Stanley Stys, *Operation Experience With Huntorf, 290 MW World's First Air Storage System Energy Transfer (ASSET) Plant*, paper presented to American Power Conference, Chicago, IL, Apr. 21-23, 1980. However, plants can be made with discharge times over 10 hours; see BBC Brown Boveri, *220 MW Sixty-Cycle Asset Plant*, Promotional Brochure (USA: BBC Brown Boveri, n.d.), Publication No. CH-T 113 390 E.

[20] Gibbs & Hill Inc., op. cit., 1984. $570/kWe total comprises $515/kWe for above ground components (e.g., turbomachinery, structures) and $55/kWe for underground salt dome cavern. Cost is based on average U.S. conditions and is not expected to be sensitive to location.

[21] Schainker and Nakhamkin, op. cit., October 1984.

[22] Ibid.

[23] Ibid.

[24] Gibbs & Hill, Inc., op. cit., April, 1984. This report provides costs in January 1984 dollars for 26.6, 50, and 100 MWe plants with 10 hour storage. Based on The Handy Whitman Index (see Definitions to this appendix), these costs were reduced by 1.7 percent to reflect mid-1983 dollars. The costs depend on the type of cavern. $487/kWe is for a 50 MWe module with salt dome cavern. The breakdown of $487/kWe is as follows: $392/kWe above-ground items and $95/kWe for salt dome cavern. For rock and aquifer storage, the total costs would be $833/kWe and $440/kWe respectively. Cost is based on average U.S. conditions and is not expected to be sensitive to location.

[25] The estimate is based on an estimate by EPRI, *Compressed Air Energy Storage: Commercialization Potential*, op. cit., 1982. Mini-CAES costs would of roughly the same magnitude.

[26] Based on 1990 distillate costs of $7.0/MM Btu, and based on a 4,000 Btu/kWh discharging heat rate, fuel cost is 28 mills/kWh. Charging-energy fuel-cost is estimated at 16 to 35 mills/kWh based on an energy-ratio of 0.78 kWh-in/kWh-out and an incoming-electricity cost of 20 to 35 mills/kWh. The total fuel cost for CAES plant thus lies between 54 and 72 mills/kWh (between (28 + 26) mills/kwh and (28 + 45) mills/kwh). (see Definitions section of this appendix for an explanation of fuel and incoming-electricity costs.)

Table A-9.—Cost and Performance of Battery Plants

May 1985 technology status	Lead-acid	Zinc-chloride
Level of technology development	Small-scale test[1]	Small scale tests[2]
Installed capacity	0.5 MWe[3]	None[4]
Reference system: general characteristics		
Reference year	1995	
Plant size[5]	20 MWe[6]	
Deployment level scenario	0-600 MWe[7]	0-2,800 MWe[8]
Lead-time[9]	2 years	
Land required[10]	0.2-0.3 acres	
Water required (gallons/day)	200-300[11]	11,000[12]
Reference system: performance parameters		
Availability	90 percent[13]	
Duty cycle[14]	peaking [15]	
Lifetime[16]		
Stacks	2,000-4,000 cycles[17]	2,000-5,000 cycles[18]
Balance of plant	30 years	30 years
Plant efficiency[19]	70-75 percent[20]	60-70 percent[21]
Discharge/charge[22]	5 hours/6.7-7.0 hours	5 hours/7.0-8.3 hours
Reference system costs:		
Capital costs[23]	$600-800/kWe[24] [25] [26]	$500-$3,000/kWe[27]
O&M costs		
Annual	1-4 mills/kWh	1-4 mills/kWh
Replacement	5-16 mills/kWh[28] [29]	2-7 mills/kWh[30] [31]
Total	6-20 mills/kWh	3-11 mills/kWh
Fuel costs	27-50 mills/kWh[32]	29-58 mills/kWh[33]

[1] This refers to the testing of a single module at the Battery Energy Storage Test (BEST) facility in New Jersey. The battery has not been demonstrated in a commercial-scale facility in the United States.

[2] Ibid.

[3] This figure refers to a demonstration unit which was in operation by the end of 1983 at the BEST facility. The battery is expected to be capable of producing 500 kWe, with a 1 hour discharge rate, at the end of its life; see GNB Batteries, Inc., *500-kWe Lead Acid Battery for Peak Shaving Energy Storage Testing and Evaluation* (Palo Alto, CA: Electric Power Research Institute, 1984), EPRI EM-3707.

[4] Note, however, that an advanced-design zinc-chloride battery operated from the end of 1983 to early 1985 at the BEST facility. The unit was capable of producing 100 kWe over 5-hour discharge periods.

[5] The zinc-chloride battery comes in 2 MWe modules; see Electric Power Research Institute, *ZnCl Batteries for Utility Applications* (Palo Alto, CA: EPRI, 1984). The lead acid battery comes in 440 kWe strings; see Exide Management & Technology Co., *Research, Development, and Demonstration of Advanced Lead-Acid Batteries for Utility Load Leveling* (Argonne, IL: Argonne National Laboratory, August 1983), ANL/OEPM-83-6.

[6] Assumes 5-hour discharge periods, or 100 MWh storage capacity; see Albert R. Landgrebe, "Operational Characteristics of High-Performance Batteries for Stationary Applications," *Advanced Energy Systems—Their Role in Our Future*, Proceedings of 19th Intersociety Energy Conversion Engineering Conference, Aug. 19-24, 1984, San Francisco, CA (U.S.: American Nuclear Society, 1984), paper 849122, pp. 1091-1096.

[7] Assumes 5-hour discharge periods, or a storage capacity under the high scenario of 30,000 MWh. The high estimate assumes that 200 MWe worth of batteries are produced during each of the following years: 1991, 1992, 1993, and 1994. This is the level of production on which the capital cost estimates are based. These batteries would begin producing electrical power in 1992, 1993, 1994, and 1995, respectively. Given 2-year lead-times for battery installations, this production scenario assumes that ten 20-MWe battery installations are intiated each year, beginning in 1990.

[8] Assumes 5-hour discharge periods, or a storage capacity under the high scenario of 8,400 MWh. The high estimate assumes that 700 MWe worth of batteries are produced during each of the following years: 1991, 1992, 1993, and 1994. This is the level of production on which the capital cost estimates are based. These batteries would begin production in 1992, 1993, 1994, and 1995, respectively. Given 2-year lead-times for battery installations, this production scenario assumes that thirty-five 20-MWe battery installations are initiated each year, beginning in 1990.

[9] Consensus from OTA Workshop on Energy Storage, Washington DC, June 6, 1984, based on 2 MWe installation, short permitting time (negligible pollution), factory assembly, and simple siting requirements.

[10] The land used depends on the energy density footprint (measured in units of kWh/sq. meter) of the battery. It is assumed that lead-acid and zinc-chloride batteries have similar footprints of 80-125 kWh/sq. meter. This footprint esimate is consistent with estimates made in the following three documents: 1) Philip C. Symons, Electrochemical Engineering Consultants, Inc., "Advanced Technology Zinc/Chlorine Batteries for Electric Utility Load-Leveling," *Advanced Energy Systems—Their Role in Our Future*, op. cit., pp. 857-862; 2) Landgrebe, et al., op. cit., 1984; 3) James Quinn, U.S. Department of Energy, "DOE Multiyear Planning," *Extended Absiracts, Sixth DOE Electrochemical Contractor's Review*, June 25-29, 1984 (Washington, DC: U.S. DOE, June 1984), CONF-840677, pp. 64-67.

[11] Based on a rough estimate that the system would use 1,000 to 1,500 gallons per week. This figure assumes a full discharge/charge cycle, five times each week. Estimate provided by John L. Del Monaco, Principal Staff Engineer, Research, Public Service Electric & Gas Co., Newark, NJ, personal correspondence with OTA staff, May 1, 1985.

[12] Based on a rough estimate that the system would use 11,000 gallons each day. This figure assumes a full discharge/charge cycle, and includes only the water requirement of the battery system itself. Most of the water is used in evaporative cooling. Estimate provided by Monaco, op. cit., 1985.

[13] From EPRI, *Technical Assessment Guide* (Palo Alto, CA: EPRI, 1982), EPRI P-2410-SR, modified (rounded off) in accordance with discussion at OTA Workshop on Energy Storage, op. cit., 1984.

[14] Batteries can also provide spinning reserve and system regulation functions; see EPRI, *Utility Battery Operations and Applications* (Palo Alto, CA: EPRI, March 1983), EPRI EM-2946-SR.

[15] Gibbs & Hill, Inc., *Overview Evaluation of New and Conventional Electrical Generating Technologies for the 1990s*, OTA contractor report, Sept. 13, 1984.

[16] The number of cycles per year depends on how the battery was used, but a figure of 250 cycles/year is often used as a reasonable average. In general, the stacks (and sumps, where appropriate) would be replaced several times over the life of the system. The remainder of the battery plant should last 30 years.

[17] Arnold Fickett, EPRI, personal correspondence with OTA staff, Aug. 30, 1984.

[18] Fickett, op. cit., 1984.

[19] AC to AC efficiency; includes the 85 percent efficiency of the power-conditioning equipment.

[20] Exide Management & Technology Co., op. cit., 1983.

[21] Round trip efficiency: kWh AC out divided by kWh in, including auxiliaries. Efficiency is constant with deployment because multiple units are used to achieve various plant sizes. Based on information provided by the following sources: 1) B.D. Brummet, et al., Energy Development Associates, *Zinc Chloride Battery Systems for Electric Utility Energy Storage*, paper prepared for the 19th Annual Intersociety Energy Conversion Engineering Conference, SAE, San Francisco, CA, August 1984; these estimates apply to the 2 MWe commercial battery. 2) OTA Workshop on Energy Storage, op. cit., 1984. 3) Energy Development Associates, *Development of the Zinc-Chloride Battery for Utility Applications* (Palo Alto, CA: EPRI, June 1983), EPRI EM-3136.

[22] Consistent with plant size and plant efficiency, assuming plant charges and discharges at 20 MWe.

[23] Battery costs are best measured in units of $/kWh. To convert the given $/kWe figures to $/kWh, divide by five.

[24] The range corresponds to the price of lead varying from $0.25/lb to $0.58/lb. The price as of August 1984 was $0.30/lb; see J.J. Kelley, Director of Research, EXIDE Corp., personal correspondence with OTA staff, Aug. 28, 1984. The cost figures assume a production of about 200 MWe/yr; see Exide Management & Technology Co., op. cit., 1983. However, lead acid battery prices should not be strongly dependent on the volume of production.

[25] Fickett, op. cit., 1984.

[26] Exide Management & Technology Co., op. cit., 1983.

[27] The low cost figure assumes a production volume of about 700 MWe/yr; see Energy Development Associates, op. cit., 1983. The price of zinc-chloride batteries should be strongly dependent on the level of production. Based also on information provided by Fickett, op. cit., 1984. The high figure is based on an estimate provided by P. Sioshansi, Southern California Edison Co., personal correspondence with OTA staff, Apr. 10, 1985. The high estimate reflects the price penalties which might be associated with early commercial units.

[28] This is a levelized value over 32 years, using a discount rate of 5 percent. The low value assumes a lifetime of 4,000 cycles, so that after 16 years parts totaling $300/kWe must be replaced. The high value assumes a lifetime of 2,000 cycles, so that these $300/kWe parts must be replaced after 8, 16, and 24 years.

[29] Fickett, op. cit., 1984.

[30] This is a levelized value over 32 years, using a discount rate of 5 percent. The low value assumes a lifetime of 4,000 cycles, so that after 16 years parts totaling $130/kWe must be replaced. The high value assumes a lifetime of 2,000 cycles, so that these $130/kWe parts must be replaced after 8, 16, and 24 years.

[31] Fickett, op. cit., 1984.

[32] The charging-energy fuel-cost is estimated to be 27 to 50/mills kWh, based on an energy ratio of 0.7 to 0.75 kWe-out/kWe-in and incoming-electricity cost in 1995 of 20 to 35 mills/kWh. (See Definitions section of this appendix for an explanation of incoming-electricity costs.)

[33] The charging-energy fuel-cost is estimated to be 29 to 58/mills kWh, based on an energy ratio of 0.6 to 0.7 kWe-out/kWe-in and incoming-electricity cost in 1995 of 20 to 35 mills/kWh. (See Definitions section of this appendix for an explanation of incoming-electricity costs.)

Table A-10.—Summaries: Cost and Performance for Reference Installations
(based on tables A-1 through A-9 in this appendix)

	Technologies						
	Solar photovoltaic		Solar	Wind	Geothermal		
May 1985 technology status	Flat plate	Concen.	Parabolic dish (mounted-engine)		Dual-flash	Large binary	Small binary
Level of technology development	Commercial	Commercial	Demo.[1]	Commercial	Commercial unit	Commercial unit	Commercial
Installed capacity	9.5 MWe	9.5 MWe	0.075 MWe	650 + MWe	none	none	22.3 MWe
Reference system: general							
Reference year	1995	1995	1995	1995	1995	1995	1995
Reference-plant size	10 MWe	10MWe	10 MWe	20 MWe	50 MWe	50 MWe	7 MWe
Reference-year installed capacity (est.)	355-4,730 MWe		5-200 MWe	1,500-2,900 MWe	12-1,830 MWe		
Lead-time	2 years	2 years	2 years	1-2 years	3 years	3 years	1 year
Land required	40-370 acres	60-320 acres	67 acres	300-2,000 acres	8-20 acres	8-20 acres	1 acre
Water required	very little	very little	very little	none	3 million gal/day	4.1 million gal/day	0.5 million gal/day
Reference-system performance parameters							
Operating availability	90-100%	90-100%	95%	95-98%	85-90%	85-90%	85-90%
Duty cycle	intermittent	intermittent	intermittent	intermittent	base	base	base
Capacity factor	20-40%	20-35%	20-35%	20-35%	70%	70%	70%
Plant lifetime	10-30 years	10-30 years	30 years	20-30 years	30 years	30 years	30 years
Plant efficiency	8-14%	12-20%	20-25%	—	7.0-8.0%	9.5-12.0%	7.0-9%
Reference-system: costs							
Capital costs	$1,000-$11,000/kWe	$1,000-$8,000/kWe	$2,000-$3,000/kWe	$900-$1,200/kWe	$1,300-$1,600/kWe	$1,500-$1,800/kWe	$1,500-$2,000/kWe
O&M costs	4-28 mills/kWh	4-23 mills/kWh	15-23 mills/kWh	6-14 mills/kWh	10-15 mills/kWh	10-15 mills/kWh	10-15 mills/kWh
Fuel costs	None	None	None	None	20-70 mills/kWh	20-70 mills/kWh	20-70 mills/kWh

[1] Only individuals modules are being demonstrated. No large multi-module installation yet exists.

Table A-10.—Summaries: Cost and Performance for Reference Installations (based on tables A-1 through A-9 in this appendix)—Continued

	Technologies							
			Fuel cells		CAES		Batteries	
May 1985 technology status	AFBC	IGCC	Large	Small	Maxi	Mini	Lead-acid	Zinc-chlor
Level of commercial development	Demo. under	Demo.	Demos. planned	Demos. operating under const., & planne	No Demo.[2]	No demo.	Demo.	Demo.
Installed U.S. capacity	none	100 MWe	None	1.5 MWe	none	none	0.5 MWe	0.1 MWe
Reference-system: general								
Reference year	1990	1990	1995	1995	1990	1990	1995	1995
Reference-plant size	150 MWe	500 MWe	11 MWe	0.4 MWe	220 MWe	50 MWe	20 MWe, 100 MWh	20 MWe, 100 MWh
Reference year U.S. installed capacity (est.)	510-735 MWe	200 MWe	40-1,200 MWe		0 MWe	0-100 MWe	0-600 MWe	0-2,800 MWe
Lead-time	5-10 years	5-10 years	3-5 years	2 years	5-8 years	4.5-6.5 years	2 years	2 years
Land required	90-218 acres	300-600 acres	0.5 acres	0.009-0.014 acre	15 acres	3 acres acres	0.2-0.3 acres	0.2-0.3
Water required	1.5 million gal/day	3-5 million gal/day	very small	very small	360,000 gals/day	100,000 gals/day	11,000 gals/day	200-300 gals/day
Reference-system: performance parameters								
Operating availability	85-87%	85%	80-90%	80-90%	90-98%	90-98%	90%	90%
Duty cycle	base/interm.	base	variable	variable	peaking/inter.	peaking/inter.	peaking	peaking
Capacity factor	20-70%	70%	40-75%	40-75%	10-20%	10-20%	10%	10%
Plant lifetime	30 years	30 years	30 years	20 years	30 years	30 years	30 years	30 years
Plant efficiency	35%	35-40%	40-44%	36-40%	51%[3]	51%[3]	70-75%[3]	60-70%
Reference-system: costs								
Capital costs	$1,260-1,580/kWe	$1,200-$1,350/kWe	$700-$3,000/kWe	$950-$3,000/kWe	$565-$600/kWe	$487-$833/kWe	$600-800 kWe	$500-3,000/kWe
O&M costs	7.66 mills/kWh	6-12 mills/kWh	4.2-11.5 mills/kWh	4.2-11.5 mills/kWh	3.6 mills/kWh	3.6 mills/kWh	6-20 mills/kWh	3-11 mills/kWh
Fuel costs	17 mills/kWh	15-17 mills/kWh	27-30 mills/kWh	30-33 mills/kWh	42-63 mills/kWh	42-63 mills/kWh	27-50 mills/kWh	29-58 mills/kWh

[2] While no demonstration plant is operating in the U.S., one has operated in Huntorf, West Germany, and a smaller one has just been completed in Italy.

[3] This efficiency is computed by dividing as follows:

$$\text{Efficiency} = \frac{\text{Electricity out}}{(\text{Electricity in}) + (\text{Fuel in})}$$

The value for the "electricity in" is based on a conversion factor of 3,413 Btu/kWh in. The computation does not consider the efficiency of the plant which generates the power provided to the compressors.

Definitions

These tables provide basic information on each technology. The data constitutes the basis for important portions of the analysis. The cost and performance characteristics listed in the tables are not definitive predictions. Rather they are reasonable approximations of the status of the technology during the 1990s, and are used to typify the technology during the last decade of the century. Great uncertainty surrounds these numbers and they should be treated for what they are: educated guesses.

Where important subcategories of any particular technology exist, and where their characteristics differ significantly from one subcategory to the next, the subcategories are listed separately. For example, photovoltaics are divided between flat-plate and concentrator modules.

May 1985 Technology Status

This section provides information on the current status of the technology.

Level of Technology Development.—The technology already may be commercially deployed, or it may be operating as a demonstration unit or pilot plant; or plans may be underway to deploy such units.

Installed Capacity.—This section of the table describes the status of the technology as of May 1, 1985. Only capacity installed and operating at that time is included in the capacity totals.

Reference System: General Characteristics

Reference Year.—For each technology a reference year is established. For technologies with lead-times of 5 years or less, the reference year is 1995. For those with lead-times longer than 5 years, the reference year is 1990. All cost and performance figures refer to the technology as it might appear in the reference year. The cost and performance figures for that year are expected to typify the cost and performance of most of the units which are deployed and operating by the end of the century.

Plant Size.—The technologies examined in this report in many instances will be deployed in a variety of sizes. The size listed in the tables is considered typical of plants installed in the 1990s. Considerable variation may occur from plant to plant, but most capacity installed during the 1990s is expected to be similar in cost and performance to the reference plant.

1995 Deployment Level Scenario.—This is the total capacity expected to be operating by January 1 of the reference year. The estimates are important because they provide an idea of the level of nationwide experience with the technology by the reference year. This in turn is an indicator of the extent of risk associated with the technology. Generally speaking, the greater the amount of capacity deployed by the reference year, the lower will be the uncertainty associated with the technology.

Lead-Time.—The lead-time is the time required to deploy a plant once a decision has been made to do so. Included is the time required for various activities prior to construction (including licensing and permitting) and construction itself.

Land Required.—This is the amount of land needed for the plant and all necessary facilities, including fuel storage areas and waste storage areas.

Water Required.—This includes any water drawn from some external source and required for the routine operation of the plant.

Reference System: Performance Parameters

Operating Availability.—Operating availability applies to the entire plant and is defined as:[1]

$$(1\text{-POR}) \times (1\text{-UOR}) \times 100$$

$$\begin{aligned} \text{where: POR} &= \text{Planned Outage Rate} \\ &= \text{(Planned Outage Hours)/(Period Hours)} \\ \text{and} \quad \text{UOR} &= \text{Unplanned Outage Rate} \\ &= \frac{\text{Unplanned Outage Hours}}{\text{(Period Hours)} - \text{(Planned Outage Hours)}} \end{aligned}$$

Several of the technologies use multiple nonconventional components in parallel, for example, multiple turbines in a wind farm or several gasifiers in an IGCC plant. In such cases also, the availability refers to the operating availability to generate rated output (and not to the individual nonconventiaonal component reliability). In all cases the figures are estimates, since no commercial units have operated over the full course of their lifetimes.

Duty Cycle and Capacity Factor.—Duty cycles are either intermittent, base, intermediate, or peaking. An installation is termed intermittent if its output cannot be controlled; this is the case with solar or wind technologies which are not coupled with any kind of energy storage system. Capacity factors for intermittent technologies will vary according to technology, time, and location. A base load system is one which runs most of the day; in the analysis such systems are assigned a capacity factor of 70 percent. A peaking system is assumed to have a capacity factor of about 10 percent, and operates during the relatively short part of the day when electricity demand is greatest.

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[1] The definition is that provided in the Electric Power Research Institutes's Technical Assessment Guide.

Capacity factors for intermediate systems are assumed to fall between the two systems, at around 20 percent. Where technologies are expected to operate under more than one duty cycle, both are stated. Actual capacity factors may be quite different form the nominal values shown.

Lifetime.—This is the time over which the entire plant would be operated commercially.

Efficiency.—This is the annual average plant efficiency, defined as the ratio of total net energy produced to total available energy contained in the fuel or resource.

Reference System: Costs

All capital and O&M costs are reported in mid-1983 dollars. Escalation of published costs, where required, was performed as per the Handy Whitman Bulletin Cost Index for electric utility construction:

Date	Index
1/1/78	159
7/1/78	166
1/1/79	175
7/1/79	183
1/1/80	193
7/1/80	199
1/1/81	210
7/1/81	219
1/1/82	225
7/1/82	230
1/1/83	233
7/1/83	238
1/1/84	242

Capital Costs.—Capital costs (total plant cost or TPC) generally represent approximate budgetary overnight constructed costs for the indicated location including an average allowance of 5 to 10 percent for engineering and home office overhead and fee and a 20 to 25 percent allowance for overall contingency. Thus:

TPC = Bare Erected Cost (BEC) × (1.05 to 1.1) × (1.2 to 1.25)

Capital costs do not include interest and escalation during construction, land costs, and other costs such as royalties, preproduction, startup, initial catalyst/chemical charges, and working capital.

O&M Costs.—These are "first year" costs, the average O&M costs expected during the reference year. In the case of both battery and fuel cell installation, a portion of cost of periodically replacing batteries or fuel-cell stacks during the installation's lifetime is included in the O&M costs.

Fuel Costs.—Electricity and fuel costs are first year annual average costs based on a typical plant in the reference year. Electricity for CAES and batteries is assumed to be generated by a base load plant, at prices expected to range from 20 to 35 mills/kWh.[2] Fuel prices are based on 1983 fuel prices, with assumed real escalation rate of 1 percent per annum for coal, and 2 percent per annum for oil and gas. The 1983 fuel prices used in making the reference year estimates are:

Fuel[3] (in dollars per million British thermal units (Btu))

	Oil		
Gas	*Residual*	*Distillate*	*Coal*
3.47	4.58	6.09	1.66

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[2] This is based on an estimate provided by William Birk, Electric Power Research Institute, personal correspondence with OTA staff, May 7, 1985. Mr. Birk indicated that EPRI uses a figure of 25 mills/kWh; for a range, he suggested 20 to 30 mills/kWh. This analysis uses a range with a higher upper limit: 20 to 25 mills/kWh.

[3] From U.S. Department of Energy, Energy Information Administration, Nov. 27, 1984. Average cost of fossil fuel receipts for steam electric plants of 50 MWe capacity or larger, 1983.

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